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OIL FIELD DEVELOPMENT

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OIL FIELD DEVELOPMENT

BY
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OIL FIELD DEVELOPMENT

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PREFACE

Although the petroleum industry owes its present state of technical development largely to economic geologists and to representatives of the mining, civil, mechanical, electrical and chemical engineering professions, it is generally recognized that a collegiate curriculum in any one of these primary branches of engineering leaves the training of the engineer deficient in one phase or another of the technology of petroleum production. With the purpose of preparing engineering students for participation in all phases of the petroleum industry, a number of universities and engineering schools have organized specialized curricula in petroleum engineering, comprising groups of selected courses extending over four or more years. Wherever introduced, the movement has met with popular response on the part of students and of engineers and others interested in the development of the petroleum industry. This industry promises to require the continued services of many engineers trained both academically and practically to a proper understanding of its specialized problems.

The author's chief purpose in preparing this book and its companion volume, entitled "Oil Field Exploitation," has been to provide a text or work of primary reference for petroleum-engineering students in that part of their curriculum which pertains to the technology of oil-field development and petroleum production. The manner of presentation of the data closely follows that developed by the author in thirty years' experience in the conduct of petroleum-production engineering courses in the University of California.

The literature of this field is abundant but widely scattered, much of the best material being unobtainable to one lacking the facilities of a comprehensive library. In the present work, an effort has been made to bring together the more important information relating to each phase of the oil-producing industry and to interpret the major facts in terms of the requirements of individuals interested in the whole rather than in the special subdivisions thereof.

The first edition of "Petroleum Production Engineering" appeared as a single volume in 1924; the "Oil Field Development" volume of the second edition in 1934. During the decade that has elapsed since that time, the technology of oil-field practice has made notable advances, necessitating a broad revision and considerable expansion in the preparation of this, the third edition. Wells are being drilled today to far

greater depths than were possible in 1934; new and more efficient types of drilling equipment have been developed; new methods of installing and cementing casing in wells have been devised, new techniques of logging, testing and completing wells perfected; the principles governing oil-field development practice have become better defined. Engineering has entered into this phase of the oil-producing industry to a greater extent than in any previous decade, with consequent improvement in methods, equipment and efficiency.

In preparation of the third edition of "Petroleum Production Engineering," the two-volume plan adopted for the second edition is retained. The present volume, entitled "Oil Field Development," sketches briefly the problems of petroleum exploration, discusses the principles and practices of oil-field development and describes the methods and equipment used in modern well drilling. The companion volume, "Oil Field Exploitation," which first appeared in 1940, deals with the principles of drainage, with production practices and equipment and with closely related subjects of handling and treating crude oil on the producer's property, and with storage and transportation of crude petroleum.

The author also has in preparation a third volume, to be entitled "Petroleum Production Economics," which will be devoted to a presentation of the economic aspects of the petroleum-producing industry. The chapter on "Acquisition of Title to Oil Lands," which was a part of the second edition of "Oil Field Development," is reserved for that volume.

It is believed that this classification of subject matter is a natural one that will be found to follow closely the plan of instruction in most engineering schools where petroleum engineering is taught. In these volumes, the needs of the petroleum-engineering student have been ever uppermost in the mind of the author; yet it is hoped that the material may be found helpful as reference manuals by the oil-company executive and the engineer of less specialized training.

Detailed acknowledgment of all sources of information drawn upon in the compilation of the data presented in this work would be impossible within the brief space here afforded, but an effort has been made to indicate the more important works of reference by a system of superior figures inserted throughout the text. These figures refer to similarly numbered items in the bibliography given at the end of each chapter. Publications of the U. S. Bureau of Mines, the American Institute of Mining and Metallurgical Engineers and the American Petroleum Institute are especially prolific sources of information, which have been freely drawn upon. The publishers of *The Petroleum Engineer* have kindly permitted reprinting of some material originally prepared by the author for publication in that journal. The author is also indebted to the many oil-field tool and equipment manufacturers who have cooperated in

supplying illustrative material and detailed information concerning their products. The author is especially grateful to the many oil-company executives and technologists who have freely shared their experience and technical information, much of which is embodied in this work. Above all, the author is indebted to the University of California for the use of research, library and other facilities and for the many opportunities for field observation that have been his privilege by reason of his association with its faculty.

LESTER CHARLES UREN.

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OIL FIELD DEVELOPMENT

CHAPTER I

PROPERTIES AND OCCURRENCE OF PETROLEUM IN NATURE

The subject matter of petroleum production engineering may logically be divided into two parts: (1) that dealing with oil-field development, and (2) that which relates to petroleum production. Each is properly regarded as a phase of the petroleum engineer's work, for which he must be adequately equipped in his academic and industrial preparation. Each of these two major subdivisions of the petroleum engineer's field of endeavor presents its own specialized problems; each has its own equipment and methods. A closely related technology is that employed in petroleum exploration, but though the engineer has points of contact and interest in this phase of the industry, it is properly entrusted to the petroleum geologist, who is necessarily a man of somewhat more specialized training. However, each must know something of the other's work. Many phases of petroleum technology they share in common.

The author bases his present effort on the conceptions outlined in the preceding paragraph. This volume is devoted to the technology of oil-field development. It is designed to be supplemented by a second volume presenting the technology of petroleum production. The present volume includes a detailed discussion of the problems of planning and conducting the field-development program, the drilling of wells and other matters incidental thereto, and traces the story of petroleum production to the point where the wells are ready to produce. The companion volume* resumes the story at this stage and carries it to the point where the crude product is turned over to the refiner. These two volumes are thus designed to cover all aspects of field exploitation.

The first two chapters of the present volume might be considered from one point of view as preliminary to its major purpose, but they are nonetheless essential to a proper understanding of the work of the petroleum production engineer. The engineer must be informed upon the properties of petroleum and its occurrence and associations in nature

* "Petroleum Production Engineering. Oil Field Exploitation," McGraw-Hill Book Company, Inc., New York, 1940.

—the subject matter of Chap. I. In Chap. II, there is interpolated a brief explanation of the methods followed by the exploration geologist. The engineer must have a general knowledge of these methods so that he may have a proper conception of all that precedes his own contribution and in order that the points of contact between his field and that of the petroleum geologist may be clearly apparent. If a sharp line of demarcation between the fields of endeavor of the geologist and engineer seems necessary, it is the author's view that the authority of the geologist should be dominant in all reconnaissance and exploration up to the actual drilling of the test well. Thereafter, through all phases of subsequent field development and exploitation, the engineer should have the guiding hand.

PHYSICAL PROPERTIES AND CHEMICAL CONSTITUTION OF PETROLEUM

Varieties and Forms of Petroleum

Petroleum is a mixture of naturally occurring hydrocarbons which may assume either the solid, liquid or gaseous state. These three phases of petroleum are transmutable, one into the other, by the application of moderate changes in temperature and pressure. Some of the constituents of petroleum are solids at ordinary earth temperatures, but the application of heat to produce a slight rise in temperature will cause them to assume liquid form and further heating to the boiling point will convert them into gases and vapors. Other constituents are vapors at ordinary temperatures, but earth pressures naturally developed within the containing rocks will cause them to condense, forming liquids. Relief of this pressure will permit the liquid to vaporize again, provided the temperature does not change. Liquid petroleum may also be converted into the solid or gaseous state by evaporation of the lighter and more volatile fractions, the latter forming gases or vapors, and the heavier fractions forming solids. The solid and gaseous forms are soluble in the liquid forms. Chemical changes, such as oxidation of the liquid petroleum, may also be instrumental in causing solidification.

In nature, all gradations ranging from hard brittle solid forms through soft waxy substances, viscous semisolids, heavy viscous liquids, light volatile liquids of waterlike consistency, and heavy vapors, to light, almost uncondensable gases may be found associated in the same deposit. As pressure, temperature and other physical and chemical changes occur, there will be continual readjustment between the different phases of associated hydrocarbons. Filtration of liquid petroleum through clays and other close-grained rocks within the earth may also bring about segregation of different constituents. It seems probable that most mineral waxes are either oxidation products derived from liquid petroleum

or residual products resulting from evaporation or segregation of the more volatile constituents. Gaseous hydrocarbons, which are always associated with liquid petroleum, are in many cases derived directly from the latter by evaporation or natural distillation; or the two, having a common origin, may accompany each other throughout their subsequent migration and accumulation.

Chemical Composition and Constitution of Petroleum

Chemically, petroleum consists of a mixture of hydrogen and carbon, the ultimate composition usually showing from 11 to 13 per cent of the former and 84 to 87 per cent of the latter. Sulphur, nitrogen and oxygen, the more important impurities, are often present to the extent of 1 per cent and occasionally to 4 per cent or even more. Helium has also been found as a constituent of some natural gases associated with liquid petroleum. Although the elemental constitution of petroleum is fairly uniform, the molecular constitution will vary within wide limits. As many as 18 different series of hydrocarbons have been identified in various crude petroleums, with numerous individual representatives of one or more of these series ordinarily present. An examination of Table I will give the reader an idea of the great variety of combinations of hydrogen and carbon that have actually been identified in petroleum. Doubtless there are many more which have not as yet been isolated.

Paraffin- and Asphaltic-base Petroleums

The difficulty of classifying petroleums by the chemical constitution of the hydrocarbon compounds present in such complexity has led to the general use of a simpler and less technical classification. A main line of distinction is drawn between what are called "paraffin-base oils" and "asphaltic-base oils." Paraffin oils yield, on reduction to low temperatures, an appreciable proportion of light-colored wax containing chiefly members of the paraffin series. This wax is not readily attacked by acids, or by ether, chloroform, carbon bisulphide or other solvents in which solid hydrocarbons are commonly soluble. Asphaltic oils on slow distillation yield a dark asphaltic residue, usually jet black in color, lustrous and with a well-developed conchoidal fracture. Asphalt thus formed is readily attacked by the stronger acids and dissolves in the above-mentioned solvents. Hydrocarbons of the polymethylene (naphthene) series predominate in most asphaltic oils. It must not be assumed that a very distinct line can be drawn between the so-called "paraffin" and "asphaltic" oils; the terms are used mainly for convenience in a broad classification. Nearly all asphaltic oils contain traces of solid paraffins and many essentially paraffin oils contain asphaltic products. Some petroleums are apparently of "mixed base," responding to the tests suggested for both paraffin and asphaltic oils in equal degree. Probably the best example of a typical paraffin-base oil is that produced in Pennsylvania. Most California, Mexican and Russian petroleums are of asphaltic base. Certain oils produced in Oklahoma, Texas and Mexico are of the mixed-base type. In nature's laboratory, hydrocarbons of one type may, by chemical readjustments of the hydrocarbon molecule or by interaction with other substances, be converted into hydrocarbons of other types.[14]

Properties of Liquid Petroleum

Commonly, petroleum occurs in the liquid phase, as an oil somewhat lighter and more viscous than water, varying in color from black, through various shades of brown

TABLE I.—CHEMICAL CONSTITUTION OF PETROLEUM

Name and group formula of series	Individual hydrocarbon compounds		Form under ordinary conditions	Remarks
	Name	Composition		
Paraffins (C_nH_{2n+2})	1. Methane	CH_4	Gaseous	These hydrocarbons may be further subdivided into a number of isomeric series—the primary, secondary and tertiary paraffins which, with equal percentage composition, differ in physical properties owing to differences of atomic arrangement within the molecules. This series is present in practically all petroleums, but preponderates in oils of "paraffin base," such as those of Pennsylvania. Lighter members of the series, gases and liquids, are those generally associated with asphalt base oils. The gases carry vapors of the liquid forms at all times. Natural gas is composed almost exclusively of the gaseous members of this series. Hydrocarbons of this series contain the highest percentage of hydrogen and are the most stable.
	2. Ethane	C_2H_6	Gaseous	
	3. Propane	C_3H_8	Gaseous	
	4. Butane	C_4H_{10}	Gaseous	
	5. Pentane	C_5H_{12}	Liquid	
	6. Hexane	C_6H_{14}	Liquid	
	7. Heptane	C_7H_{16}	Liquid	
	8. Octane to	C_8H_{18}	Liquid	
	16. Hexadecane	$C_{16}H_{34}$	Liquid	
	18. Octadecane	$C_{18}H_{38}$	Solid	
	20. Eicosane to	$C_{20}H_{42}$	Solid	
	35. Pentatricontane	$C_{35}H_{72}$	Solid	
Olefines (C_nH_{2n}) Polymethylenes ($C_nH_{2n})_x$ (Originally called Naphthenes)	Ethylene	C_2H_4	Gaseous	These hydrocarbons are relatively unsaturated and constitute the so-called "open-chain" hydrocarbons. They include several independent series, differing in physical and chemical characteristics although identical in percentage composition. One of these, the olefine series, is relatively unstable. They have been identified in Canadian oils. The polymethylenes are relatively persistent and occur in California and Russian oils. They predominate in most oils of asphalt base.
	Propylene	C_3H_6	Gaseous	
	Butylene	C_4H_8	Gaseous	
	Amylene	C_5H_{10}	Liquid	
	Hexylene	C_6H_{12}	Liquid	
	Eicosylene	$C_{20}H_{40}$	Liquid	
	Cerolene	$C_{27}H_{54}$	Solid	
	Molene	$C_{30}H_{60}$	Solid	
Acetylenes (C_nH_{2n-2})		$C_{12}H_{22}$	$C_{19}H_{36}$	Lower members of this series have not been found in petroleum. Higher members are characteristic of oils from Texas, Louisiana, Ohio and some California fields.
		$C_{14}H_{26}$	$C_{21}H_{40}$	
			$C_{22}H_{42}$	
		$C_{16}H_{30}$	$C_{24}H_{46}$	
Turpenes (C_nH_{2n-4})		$C_{23}H_{42}$		Higher members of this series are found generally in small amounts in all crudes of low specific gravity, particularly in Ohio, Texas and California oils.
		$C_{24}H_{44}$		
		$C_{25}H_{46}$		
Benzenes (C_nH_{2n-6}) (Aromatic Hydrocarbons)	Benzene	C_6H_6		Found in all crude petroleums in small amounts. Particularly in East Indian, Roumanian and California oils.
	Toluene	C_7H_8		
	Xylene	C_8H_{10}		
	Cumene	C_9H_{12}		
	Cymene, etc.	$C_{10}H_{14}$		

Higher Series: The series (C_nH_{2n-8}) and (C_nH_{2n-10}) are rarely found in petroleum but occur in small amounts in heavy California and Russian oils. Naphthalene ($C_{10}H_8$), found in Rangoon, Russian and California oils, is probably the only member of the (C_nH_{2n-12}) series that has been positively identified. In all, 18 series (to C_nH_{2n-32}) have been identified in crude petroleum.

TABLE II.—PHYSICAL PROPERTIES OF LIQUID PETROLEUM

Property	Remarks
Color	By transmitted light, pale yellow through various shades of red and brown to black. By reflected light, greenish or bluish shades of yellow, red, brown or black.
Refractive index	Measured with Zeiss refractometer, varies from 1.39 to 1.49.
Specific rotatory power.	Measured with Nicol prism, generally ranges between 0° and 1.2°. Occasionally it may rise as high as 3.1°.
Odor	Aromatic; resembling gasoline, coal tar, oil of cedar, pyridine, etc.
Density	Specific gravity ranges between .75 and 1.01; Baumé gravity from 63° to 10°–. Generally ranges between .82 and .96 in specific gravity.*
Coefficient of expansion.	Varies from .00036 to .00096; generally between .00070 and .00085 (coefficients for Fahrenheit temperature scale).
Boiling point	Not constant. For different constituents ranges from less than normal atmospheric temperature to upward of 300°C.
Freezing point	Ranges from 60°F. down to temperatures as low as –50°F.
Flash point	–12°C. to 110°C., using open cup tester on a large group of California oils.
Burning point	2°C. to 155°C., using open cup tester on a large group of California oils.
Calorific power	Varies from 15,350 to 22,000 B.t.u. per pound, or from 8,500 to 11,350 calories per gram. Generally ranges between 18,000 and 19,000 B.t.u. per pound.
Specific heat	Ranges between .40 and .52. Averages about .45 for most crudes.
Latent heat of vaporization.	Ranges between 130 and 160 B.t.u. per pound for most paraffin and methylene hydrocarbons.
Viscosity	2.3 to 1,300 Engler for a large group of California oils at 60°F.
Radioactivity	Some of the lighter petroleums display radioactive power, which is thought to have some significance in determining their origin.

*Two so-called Baumé scales for comparing the densities of liquids lighter than water are recognized, but one endorsed by the American Petroleum Institute is now universally used throughout the American petroleum industry. The A.P.I. scale has the following relation to specific gravity:

$$\text{Specific gravity} = \frac{141.5}{131.5 + \text{degrees A.P.I.}}$$

or, conversely,

$$\text{Degrees A.P.I.} = \frac{141.5}{\text{specific gravity}} - 131.5$$

In oil-density measurements, the temperature of the oil should always be 60°F. If measured at any other temperature, a correction must be applied to the observed gravity reading.

and green, to a light amber; or, in rare instances, it may be almost colorless. It has a distinctive odor, sometimes described as "aromatic," resembling that of gasoline, one of the more volatile constituents. The odor is often disagreeable, particularly if the oil is contaminated with sulphur or nitrogen compounds. Liquid petroleum has a peculiar property of reflecting light, developing bluish or greenish color effects, known as "bloom," which are not in evidence when the liquid is viewed by transmitted light. Liquid petroleum spread in a thin film on a water surface also develops a characteristic iridescence. Table II presents the more important physical characteristics of liquid petroleum.

Solid Forms of Petroleum

The naturally occurring solid forms of petroleum include the mineral waxes, paraffin and asphalt. Different varieties of these substances have been given such mineralogical names as ozocerite, gilsonite, grahamite, elaterite, alberite, etc. The reader is referred to any of the books on descriptive mineralogy for descriptions of these different varieties of petroleum in solid form.

Composition and Properties of Gaseous Forms of Petroleum

Gaseous forms of petroleum, commonly called "natural gas," consist of mixtures of hydrocarbon gases and vapors, the more important of which are methane, ethane,

Table III.—Physical and Chemical Characteristics of Natural Gases

Source of gas	Sp. gr. air = 1	B.t.u. per cu. ft.	CH_4, per cent	Higher* hydrocarbons, per cent	N_2, per cent	CO_2,† per cent
Average Pennsylvania and West Virginia	.624	1,145	80.85	14.00	4.60	.00
Average Ohio and Indiana	.637	1,095	83.60	.30	3.60	.20
Average Kansas	.645	1,100	93.65	.25	4.80	.30
Santa Maria Field, Cal	.810	1,044	62.70	20.20	1.40	15.50
Coalinga Field, Cal	.660	937	88.00	.00	.90	11.10
McKittrick Field, Cal	.850	724	66.20	1.00	2.40	30.40
Sunset Field, Cal	.660	934	87.70	.00	1.80	10.50
Fullerton Field, Cal	.630	1,100	86.70	9.50	2.10	1.70
Kern River Field, Cal	.660	1,047	84.30	8.00	1.20	6.50
Hogshooter Field, Okla	.580	1,004	94.30	.00	4.60	1.10
Hogshooter Field, Okla	.910	1,548	23.60	69.70	1.30	2.50
Titusville, Pa	.990	1,765	6.60	91.10	2.30	.00
Caddo Field, La	.....	.....	95.00	.....	2.56	2.34

* Recorded as ethane (C_2H_6) in most analyses, though in "wet" gases the hydrocarbons present are frequently propane, butane, pentane and hexane.

† Carbon monoxide, oxygen and hydrogen, recorded in many analyses of natural gas, are probably the result either of contamination of the sample with air or of inappropriate methods of analysis. According to *U. S Bur. Mines Bull.* 88, they are never present in natural gas. The gaseous members of the olefin series are also unusual. Hydrogen sulphide and sulphur dioxide are frequently present as impurities.

propane, butane, pentane and hexane, all of the paraffin series (C_nH_{2n+2}). Petroleum gases are colorless and possess a petroleum odor which is occasionally masked by the stronger odor of impurities, such as hydrogen sulphide or sulphur dioxide. The presence of water vapor sometimes gives natural gas a white, foglike appearance. Table III indicates the composition and properties of a number of typical natural gases.

Petroleum Not a Mineral

Since petroleum is a complex substance of *varying* chemical composition, it is strictly speaking not a mineral. It may be properly designated, however, as a mineral substance or as an aggregation of minerals.

Thermal Properties of Petroleum

All hydrocarbons are inflammable, whether in the solid, liquid or gaseous state, though the solid and heavy, viscous liquid forms are relatively less so, because of the difficulty of securing admixture with the necessary air to support combustion. The gases are frequently explosive, and the lighter, more volatile liquids, surrounded by an inflammable blanket of their own vapor, are readily ignited and will be completely consumed by the resulting flame. The flash point, or that temperature at which inflammable gases are given off, the fire point, or the temperature at which the liquid will burn, and the calorific value are thermal properties which enter as important variables in testing petroleum and petroleum products for specific purposes (see Table II).

Distillation Products of Petroleum

Distillation is an important physical process to which petroleum is subjected in refining and in isolating its various components to determine their composition or suitability for different purposes. Since petroleum is a mixture of a large number of substances of varying boiling points, the more volatile constituents of low boiling point are distilled first when heat is applied in the distillation process, and the higher boiling fractions are evolved in succession as their respective boiling points are reached. Natural distillation of petroleum within the earth as a result of high earth temperatures, and variation in the pressure to which it is subjected during natural distillation, may explain in large part the marked differences in physical and chemical characteristics. Because of the difficulty of making chemical analyses of petroleum, it is customary to subject the oil to fractional distillation, reporting as a rough indication of its value for refining purposes, the percentages of distillate obtained between stated boiling points.[11,12,21]

ORIGIN OF PETROLEUM

Though many eminent geologists and chemists have investigated and offered theories and experimental evidence in explanation of the origin of petroleum, the matter is still a subject of scientific controversy. Several of these theories seem to offer plausible explanations of the source and manner of formation of specific deposits, but apparently none are of general application.

The various theories that appear in the literature of this subject are usually classified into two groups: the so-called "inorganic" and

"organic" theories. The former attempt to explain the formation of petroleum as a result of geochemical reactions between water or carbon dioxide and various inorganic substances, such as carbides and carbonates of the metals. The organic theories assume that petroleum is a decomposition product of vegetable and animal organisms that existed within certain periods of geologic time. Table IV presents the principal ideas on which a number of the better known theories of each group are based.[1]

Inorganic Theories Discredited

The inorganic theories, formerly given popular credence, have in recent years given way to theories based on organic evidence, organic origin being now generally accepted. A number of facts have been responsible for the general discrediting of the inorganic theories. Petroleum is notably absent in the rocks formed during geologic periods in which vulcanism was most active. No one has been able to produce it synthetically from exclusively inorganic materials. Furthermore, the inorganic compounds assumed to be responsible for its formation are rare in nature.

Organic Theories Plausible

In the case of the organic theories on the other hand, there is abundant corroborative evidence, both in nature and from the laboratory, that petroleum may be derived from organic materials of either animal or vegetable origin. Petroleum deposits are in some instances found in close relation with coal deposits of known vegetable origin. In other cases, fish, diatoms, foraminifera, algae and other marine organisms have evidently been the source of petroleum. Carbonaceous shales and sandstones are of widespread occurrence in petroliferous areas and frequently contain sufficient organic material to account for the formation of large deposits of petroleum. The conversion of such organic materials into petroleum has been demonstrated in the laboratory and has been proved possible under conditions normally prevailing in nature.[33]

It seems probable that transformation of the parent organic material into petroleum has proceeded, in the absence of air, in muds, shales and sands along the bottoms of shallow lagoons, estuaries, bays and lakes. It has also been suggested that salt water and certain anaerobic bacteria may be essential to the transformation, the former preventing rapid decomposition of the parent material during the transition stage and the latter converting the waxy, fatty and resinous constituents of animal and plant organisms into hydrocarbons. Various nitrogen and sulphur compounds often found in association with petroleum are considered products of these same biochemical reactions. Temperature and pressure are undoubtedly important physical variables that influence the character of the decomposition products. Possibly in some cases petroleum is formed by actual distillation, in porous formations within the earth, of solid hydrocarbons derived from the parent organic material.

Natural Distillation of Petroleum from Solid Carbonaceous Materials

It seems reasonable to assume that the liquid and solid hydrocarbons have been in many cases subjected to earth temperatures sufficiently high to bring about their vaporization. Some theories assume that the primary hydrocarbon resulting from decomposition of the parent organic material is a solid, conforming in its general characteristics to the "kerogen" present in oil shales. Just as oil is distilled by artifi-

TABLE IV.—THEORIES ADVANCED IN EXPLANATION OF THE ORIGIN OF PETROLEUM

Name of theory or its originator	Salient features	Evidence
Inorganic Theories		
Berthelot's alkaline carbide theory.	Deep-seated deposits of alkaline metals in the free state react with CO_2 at high temperatures, forming alkaline carbides. These, on contact with water, liberate acetylene which, through subsequent processes of polymerization and condensation, forms petroleum.	Evidence lacking. Neither free alkaline metals nor carbides found in nature.
Mendeleef's carbide theory...	Iron carbides within the earth, on contact with percolating waters, form acetylene which escapes through fissures to overlying porous rocks and there condenses.	See above. Magnetic iron oxides would also be formed as a product of these reactions. Magnetic irregularities have been noted in the vicinity of some oil fields.
Moissan's volcanic theory....	Moissan suggests that volcanic explosions may be caused by the action of water on subterranean carbides.	Small quantities of petroleum noted in volcanic lavas near Etna and in Japan. Petroleum also associated with volcanic rocks in Mexico and Java.
Sokolov's cosmic theory......	Petroleum considered to be an original product resulting from the combination of carbon and hydrogen in the cosmic mass during the consolidation of the earth.	Small quantities of hydrocarbon occasionally found in meteorites.
Limestone, gypsum and hot-water theory.	Reactions between carbonate and sulphate of lime in the presence of water, at temperatures sufficient to dissociate the water, theoretically may form hydrocarbons.	Practically, it has been found impossible to demonstrate this reaction in the laboratory.
Organic Theories		
Engler's animal-origin theory.	Petroleum formed by a process of putrefaction of animal remains. Nitrogen thus eliminated and residual fats converted by earth heat and pressure into petroleum. Activity of anaerobic bacteria thought to play a part in the reactions.	Oils resembling petroleum may be distilled from sediments containing fish remains. Many petroleum deposits associated with marine sediments contain an abundance of foraminifera.
Höfer's vegetable-origin theory.	Petroleum formed by decay of accumulated vegetable refuse under conditions which prevent oxidation and evaporation of the liquid products formed.	Deposits of petroleum found in close association with sedimentary deposits containing diatoms, seaweed, peat, lignite, coal and oil shale of known vegetable origin. Oils closely resembling petroleum may be distilled from these substances.
Hydrogenation of coal or other carbonaceous materials.	Solid organic materials converted into liquid hydrocarbons by combination with free hydrogen at high pressures and temperatures in the presence of a suitable catalyzer such as nickel.	Hydrogenation of coal in the laboratory and in commercial plants. The ash of some petroleums is chiefly nickel. However, the existence of free hydrogen in nature is yet to be demonstrated.
Synthesis of carbon monoxide and hydrogen.	Gaseous products containing carbon are converted into liquid hydrocarbons by combination with free hydrogen in presence of a suitable catalyst, such as iron, cobalt, nickel, etc.	In the Fischer-Tropsch process, gases derived from coal, oil shale or natural gas are synthesized to form hydrocarbon motor fuels.

cial means from such shales, so it is thought liquid petroleum may be formed by natural distillation within the containing rocks. Hydrocarbon vapors, thus formed, could migrate much more readily than the liquid forms to structures favorable for their accumulation. On subsequent cooling to lower temperatures the vapor so accumulated would condense, forming liquid petroleum. Variation in heat and pressure conditions during this natural distillation process, as well as differences in the character of the parent organic material, would account for variation in the types of oil produced. The entire process, as outlined, is analogous in every way to that practiced in the modern refinery.[34]

Weight is given to this theory by the field evidence obtained from petroleum deposits found in close association with sedimentary strata containing coal. The oil in such cases is clearly a natural distillation product obtained by metamorphism of the coal, the hydrocarbons being driven off, leaving the coal richer in fixed carbon. It is found, furthermore, that the degree of metamorphism which the coal has suffered is a reliable indication of the presence or absence of oil in the vicinity. White has shown that in those regions in which the coals are but little altered by dynamic influence, and where they have a low fixed-carbon ratio, the oils are heavy and of low grade.* On the other hand, in regions of more advanced alteration, where the coals have a higher fixed-carbon ratio, the oils are correspondingly light and of higher grade. Oil is seldom found in regions where the associated coal deposits contain more than 65 per cent of fixed carbon. Considerable gas and a little oil are found associated with 60 to 65 per cent carbon coals, but most of the oil is found where coals range between 50 and 55 per cent in fixed carbon.

ACCUMULATION OF PETROLEUM

It is apparent that, whatever the theory accepted in explanation of the origin of petroleum, the oil would originally be widely scattered through the containing rocks. It must subsequently be subjected to an agency which will effect a concentration of these disseminated particles before the formation of a deposit of commercial proportions becomes possible. Since the dimensions of petroleum deposits are relatively small in comparison with the areas over which the small particles of oil were originally formed, it is evident that this "migration" of petroleum may necessitate movements over considerable distances. The rocks in which accumulation occurs are seldom those in which the petroleum was formed, and accumulations are occasionally found in formations stratigraphically unrelated with those containing the parent material.

Natural Forces Which Assist in Bringing About Migration and Accumulation of Petroleum

The forces at work in nature which assist in bringing about migration and accumulation of petroleum include: (1) gas pressure; (2) gravity, in association with the buoyant force of water resulting from difference in density, or the gravity differential between water and petroleum; (3)

* White, D., Some Relations in Origin between Coal and Petroleum, *Washington Acad. Sci. Jour.*, vol. 5, No. 6, pp. 189–212, 1915.

hydraulic pressure developed by flowing water in subterranean channels; (4) earth pressure, the result of diastrophism; (5) compaction of sediments; and (6) capillarity which, by reason of differences in surface tension between water and petroleum, results in segregation of the two fluids and concentration of petroleum in the larger rock pores.

Gas Pressure.—It has been stated previously in this chapter that natural gas is a universal accompaniment of liquid petroleum. The "fixed" hydrocarbon gases (principally methane and ethane) are probably formed as a product of the same reactions that are responsible for the formation of liquid petroleum. Furthermore, as we have seen, the liquid hydrocarbons have a high vapor pressure, tending to enclose themselves in an atmosphere of their own vapors. This vapor pressure increases with temperature so that, at temperatures readily attainable within the earth's surface, some of the hydrocarbons constituting petroleum may at times exist only in the vapor phase. Even though subsequent condensation of these vapors should occur, large quantities of methane, which is not condensable at ordinary earth temperatures and pressures, will ordinarily be present. Though these hydrocarbon vapors and gases are somewhat soluble in the liquid hydrocarbons, it is evident that the processes involved could easily account for large volumes of free natural gas in close association with deposits of liquid petroleum. The field evidence confirms this reasoning, gas being always in evidence wherever liquid petroleum is produced—frequently under high pressures and in enormous volumes. Gas pressures as high as 5,000 lb. per sq. in. are sometimes recorded. Individual wells drilled into certain "pools" have had initial productions in excess of 100,000,000 cu. ft. per day and have averaged many millions of cubic feet per day for long periods of time. A certain relationship between gas pressure and depth is noted, the formational pressure or "rock pressure" ranging in most instances between 36 and 43 lb. per 100 ft. of depth. This phenomenon is theoretically related to the static pressure of ground water, which averages about 44 lb. per 100 ft. of depth below the level of water in the formation (see page 436).

Gas moves with freedom through the interstices of porous rocks. It exerts pressure equally in all directions, and in its effort to flow from high-pressure toward low-pressure areas within the earth, liquid petroleum is carried along with it. The liquid petroleum may be carried as films surrounding gas bubbles, or it may be pushed through the rocks in relatively large volumes ahead of a body of gas. Gas in solution in petroleum reduces its viscosity and thus indirectly assists other natural forces in bringing about its migration. Solubility of gas in petroleum increases directly as the pressure, so that at high pressures very large volumes of gas may thus be held in the liquid phase.

Selective Action of Gravity on Rock Fluids. The Anticlinal Theory.—Below the level of the water table, where temperature and pressure conditions permit, rocks are generally saturated with water. Movement of gas as well as of liquid petroleum is undoubtedly brought about in many instances by the selective action of gravity on the rock fluids. Inundated globules of oil tend to float in water by reason of their lower density and accumulate in the upper horizons of the porous strata to which they have access. Such migration is not necessarily vertically upward, up-dip movement along the under side of an impervious capping often contributing a considerable horizontal component. If we consider the gas pressure and hydrostatic forces at work sufficient to overcome the resistance offered by the rock pores, it is obvious that the oil globules will continue to move up-dip until they are trapped or until they reach the highest point in the stratum in which they are stored.

Unless the oil-containing stratum is covered by an unbroken, impervious cap rock, the oil will escape to overlying formations until it encounters an impervious stratum. The crests of domes and anticlines serve in this way as elevated structural traps in which the oil and gas, under the influence of hydrostatic forces, tend to accumulate (see Fig. 1). Gas, being lighter than oil, will tend to accumulate under the influence of these same forces in the upper levels of the anticlinal trap, while oil will occupy an intermediate zone between the gas and the underlying water. So many oil fields show evidence of anticlinal structure, with the major accumulations invariably found at or near the structural crest, that prospectors for petroleum seek, first of all, areas in which anticlinal structure is in evidence. The "anticlinal theory," embodying the

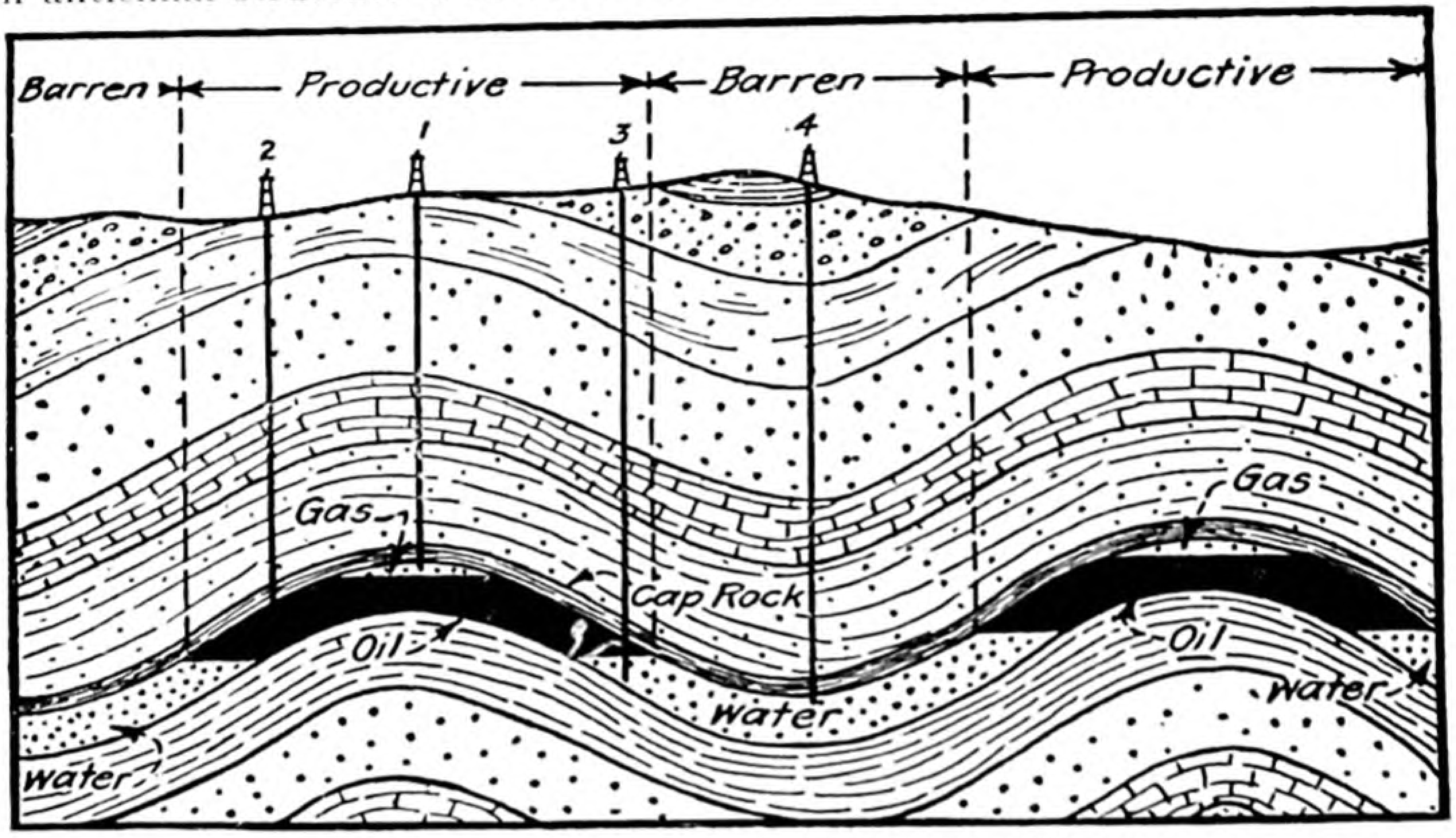


FIG. 1.—Illustrating ideal anticlinal conditions.

The figure shows two productive symmetrical anticlines with intervening barren syncline. Gravitational segregation of gas, oil and water in the anticlinal crests of the oil-bearing stratum has been complete. Well No. 1 is a gas well, but No. 2 is an oil well; No. 3 produces both oil and water; No. 4 is a water well.

principles just presented, is now universally accepted as the controlling factor in oil accumulation.

Consideration of Fig. 1 will make it clear to the reader that inclination of the strata must have a considerable influence on the effectiveness with which gravitational forces causing migration may operate. The greater the dip of the formation, the more rapidly will translation of the oil and gas be effected, and the more complete will be their separation from water and from each other. Other factors, such as rock permeability, gas pressure and gravity and viscosity of the oil, will also influence the rate of migration and the completeness of separation of the rock fluids.

Migratory Ground Waters. Hydraulic Pressure.—It is definitely known that meteoric waters are often migratory and flow within the earth's surface in well-defined channels. Such movement, while sluggish, owing to the resistance to flow which it must overcome, is persistent, and the water may flow in one direction over long periods of time. It is thought that the carrying effect of ground waters in continual motion in this way may be instrumental in transporting globules of oil. We may think of this as due to hydraulic pressure, a force obviously of quite different character than that developed by hydrostatic pressure as described above. Globules of oil flowing in underground water channels may by reason of their lower specific gravity be trapped in anticlinal crests, just as driftwood accumulates in quiet pools along the shore lines of surface streams.

Earth Pressure. Diastrophism.—When sedimentary strata are subjected to forces which bring about the formation of anticlinal and synclinal folds, great differences in pressure within the deformed strata must result. The inner portion of a fold is subjected to compression, the outer to tension. Both result in shrinkage of pore space and expulsion of fluids formerly contained within the rock. Diastrophism varies in intensity at different points within the earth's crust, and fluids expelled from rocks in the region of greatest deformity flow toward the areas where folding is less intense and where more moderate pressures prevail. During this expulsion of the rock fluids, water, oil and gas may be forced to migrate and will tend to accumulate in anticlinal crests in much the same manner as in the case of direct hydraulic pressure.

Compaction of Sediments.—Aside from diastrophism, earth pressure finds expression in another way through the application of direct weight of superimposed sediments. When a stratum of shale, clay or sand is laid down under water, its percentage porosity is high, but as additional strata are superimposed, their weight operates to compact the mineral particles, reducing the pore space between and thus expelling a portion of the contained fluids. Compaction of a shale in this way may result in a reduction of porosity from upward of 80 per cent to but a few per cent of the volume of the rock; hence, large volumes of fluid may be squeezed out and forced to migrate to regions of lower pressure or to "dry" or partly saturated rocks of greater porosity. Oil may thus be largely expelled from a shale source rock and forced to migrate to a suitable reservoir rock.[38]

Capillarity.—Water has a surface tension about 2½ times that of petroleum; therefore capillarity is proportionately effective in its lifting power. The openings in rocks are, for the most part, of capillary size, and through capillary attraction they exert a selective action on the two fluids, drawing water into close-grained rocks and displacing petroleum which is forced into rocks having larger pore spaces. Although it would appear difficult to explain the extensive migrations of petroleum that have occurred in some instances as due to the operation of differential capillarity, it seems reasonable to assume that this force may be instrumental in effecting local segregations of water and oil. Lenticular segregation of oil in sands may be explained on this basis, and capillarity may assist in forcing petroleum out of the rocks in which it is formed, into more permeable rocks, where gas, hydrostatic, hydraulic and earth pressure may be effective in bringing about the major concentrations.

LITHOLOGIC CHARACTER OF PETROLIFEROUS ROCKS AND ASSOCIATED ROCKS

Oil and gas migrate from the "source rocks" in which the parent organic matter was deposited, through "carrier beds" to the "reservoir rocks" in which they are accumulated and stored by nature. Upward escape of the reservoir fluids is prevented by an impervious "cap rock." An essential condition in the formation of a commercially important oil or gas accumulation is that there must be a porous, fractured, cavernous or creviced stratum in which the fluids may accumulate; and this must be overlain by an impervious cap rock which prevents escape of the fluids after their concentration and segregation have been effected.[40,44]

Reservoir Rocks

An oil and gas reservoir may be defined as a body of porous and permeable rock containing oil and gas through which fluids may move

toward recovery openings under the pressures that exist or that can be applied. All communicating pore space within the productive formation is properly a part of the reservoir, which thus may include several or many individual rock strata and may encompass bodies of impermeable or barren rock. The lateral expanse of such a reservoir is contingent upon continuity of pore space and the ability of fluids to move through the rock pores under the pressure available.

The lithologic properties of the reservoir rock are important in determining storage capacity, resistance to flow and the rate at which fluids may enter the wells. The size and shape of the pore spaces, their continuity and the percentage of the total volume of the rock that they represent are important factors. Reservoir rocks are usually sandstone, semiconsolidated sands, conglomerates or limestones: rocks which afford sufficient space to permit storage of fluids to the extent of 10 per cent or more of the volume of the rock and having pore spaces sufficiently large and continuous to allow movement of fluids through them. Shales and clays may also contain important volumes of oil, but their pores are usually too small to allow flow of oil through them at commercial rates.

Sandstone Reservoir Rocks.—Sands and sandstones are formed as a result of processes of sedimentation in which mineral fragments of assorted sizes and shapes are gradually fitted together under water, later to be compacted by the weight of superimposed strata. Tabular faces of grains assume similar orientation, developing parallel bedding planes. Small grains are deposited in the interstices between large grains and thus a condition approaching minimum porosity for unconsolidated sand is attained. Subsequent introduction of cementing material between the grains may consolidate them into a coherent mass, thus further reducing the porosity and the size of pore openings. Individual sand grains occur in an infinite variety of sizes and shapes and may be angular, subangular or rounded depending upon the amount of abrasion that they have suffered. The minerals present are of little significance, except as a means of identifying and correlating strata. Quartz, feldspar, chlorite, mica, magnetite, ilmenite, amphibole, monazite and others of the more durable rock-forming minerals are common constituents of petroliferous as well as other sandstones.

Limestone Reservoir Rocks.—Pore openings in limestone are characteristically much less uniform in shape and size than those of sands and sandstones. The rock openings are in many cases formed by solution and weathering and are extremely irregular in shape and distribution. Formed at prehistoric erosion surfaces, they are now found below younger formations resting unconformably upon them. In some cases, limestone formations develop porosity by fracturing as a result of crustal movement along joint planes. In some fields the reservoir rock is composed of calcareous sands or oölitic masses having primary porosity. Other types of dolomitic limestone reservoir rocks have porosity resulting from shrinkage as a result of mineralogical changes.[54]

Porosity of Reservoir Rocks.—The storage capacity afforded by a rock stratum for fluids is measured solely by its interstitial pore space. In addition to the pore openings left between grains in a granular rock, this may include openings of other types, such as joint and cleavage planes, vesicular openings, solution cavities, crevices formed

by fracturing and angular cavities in brecciated rock masses. High porosity in a granular rock results from uniformity in size and shape of grains and is influenced also by their arrangement. It can be demonstrated mathematically that true spheres of uniform size, packed as closely as possible, will have a porosity of 25.95 per cent, irrespective of the diameter of the spheres. A cubic foot of sand or sandstone presents a very large surface to the fluids stored within it, and a vast number of individual communicating pores are formed between the grains comprising it.

In referring to the porosity of a rock in a quantitative sense, allusion is usually made to the ratio, expressed in per cent, that the volume of the pore space bears to the total bulk volume. This varies within wide limits, ranging from zero to as much as 40 per cent. Porosities in excess of 30 per cent are uncommon, however, and most commercial-oil sands range between 10 and 25 per cent. Rocks of less than 10 per cent porosity may yield oil at commercial rates only when very thick and when formation pressures are high.[55]

Permeability of Reservoir Rocks.—The permeability of a reservoir rock, usually expressed in "millidarcys," is a measure of the resistance offered to movement of fluids through its pore spaces. Although the size of the grains composing a sand or sandstone, if uniform, does not influence the storage capacity, the size of the pore spaces between the grains will determine what fluids may enter and will have a marked effect upon the resistance offered to movement of fluids through the rock. Oil is less readily absorbed by rock pores than water and flows with greater resistance. Natural gas, although entering the rock pores more readily than water, may nevertheless be displaced by the latter in a fine-grained sandstone as a result of capillary action. It seems probable that in very small rock openings, capillarity exerts a retentive force so powerful that the contained fluids are held practically stationary within the rock pores, though differential pressures of the order of hundreds of pounds per square inch may be operative.

Productive Zones.—Frequently a formational interval of considerable thickness, perhaps hundreds of feet of oil-bearing strata, will be included within the productive formation. Seldom, however, will all the beds so included yield oil to the wells. The more porous and permeable beds will yield oil and/or gas, but interstratified with them may be relatively "tight" beds of shale or sandstone that are barren or, if they contain oil, are so impermeable that they do not freely yield their contained fluids to penetrating wells. If such a series of strata contains no well-defined and continuous body of shale or other impermeable material, or strata that are occupied wholly by water, it may be spoken of as a productive "zone." A zone may be made up of lenticular bodies of sand and shale, some component members being productive, others not. Thus, a productive zone may comprise several or many individual reservoirs. Also, there may be several separate zones of production in a given structure, one below another and separated by continuous, impermeable strata; and the several zones do not necessarily have the same lateral expanse.

Impervious Cap Rocks.—Cap rocks overlying productive reservoir rocks are almost invariably argillaceous in character—clays, shales, slates or marls. Such rocks, in addition to being impervious to oil, are often pliable and do not fracture readily when bent into anticlinal folds. The thickness of the cap rock is often only a few feet, though it must be sufficient, together with the pressure of the overlying rock masses, to withstand the fluid pressure in the underlying reservoir rock if it is to be effective in retaining oil and gas.

RESERVOIR CONDITIONS IN OIL-PRODUCING FIELDS

Oil, accumulated by the methods described in an earlier section, is found in well-defined areas, usually occupying the crests of anticlines or

domes or other structurally high portions of the reservoir rock to which they have access. Usually the reservoir strata surrounding the productive areas will be found occupied by "edge" water (see page 453). The fluids present in the reservoir rock exist under a pressure imposed by the static head of ground water accumulated and trapped in the communicating strata. Connate water is usually also found distributed through the oil-bearing portion of the reservoir strata, occupying the smaller pore openings, sometimes to the extent of 20 per cent or more of the total pore space.

Original formation pressures in oil reservoirs increase directly with depth below the water table in the formations with which they are in communication, the observed pressures averaging about 40 lb. per 100 ft. of depth. Earth temperatures also increase more or less directly with depth, the geothermal gradient in the vicinity of oil-bearing structures being frequently about 1°F. above average atmospheric temperature for each 50 ft. of depth. Thus, an oil reservoir encountered at a depth of, say, 5,000 ft. might be expected, under average conditions, to be under an initial pressure of $50 \times 40 = 2{,}000$ lb. per sq. in. and a temperature of $60 + 100 = 160$°F.[57,63]

Natural gas associated with liquid petroleum is partly dissolved in the oil, while "free" gas is often accumulated at the crest of the structure as a "gas cap" (see Fig. 1). The solution-capacity of liquid petroleum for natural gas varies directly with the pressure imposed and inversely with temperature. In deep-seated reservoir rocks, each barrel of oil may contain several hundred cubic feet of gas in solution; however, reservoir oils are often undersaturated at the existing pressure. Natural gas in solution in petroleum reduces its viscosity and surface tension so that it flows more freely through the pore spaces of the reservoir rock when heavily saturated with dissolved gas under high pressure. Petroleum containing large amounts of gas in solution under high pressure also has lower density and occupies a somewhat larger volume than does the same oil after release of pressure and escape of dissolved gas. High vapor-pressure components of the oil under high-pressure reservoir conditions may appear as vapor components of natural gas when reservoir pressure is reduced by partial depletion of the reservoir. On the other hand, in the so-called "distillate fields," certain components that appear as liquids under surface conditions exist as vapors under the high temperatures prevailing in deep-seated reservoirs.

Methane is nearly always the most abundant constituent of natural gas. Since its critical temperature is below temperatures possible within the earth's crust, it may exist only as a gas, except insofar as it is dissolved in the oil or adsorbed on the mineral surfaces of the reservoir

rock. At pressures above 732 lb. per sq. in., its critical pressure, ethane may exist as a liquid if the temperature is lower than 89°F., its critical temperature. Hydrocarbons of greater molecular weight than ethane exist in most reservoirs at temperatures below their critical temperatures, and pressures necessary to liquefy them are easily possible, even at moderate depths. The physical state of each of the hydrocarbon components of natural gas under the pressures and temperatures existing in deep-seated reservoirs is sometimes difficult of determination, inasmuch as partial pressure effects play an important role and the complex hydrocarbon mixtures do not conform even approximately with the gas laws.

Physical and Chemical Effects of Associated Rocks on Petroleum

Laboratory investigation has demonstrated that oil filtering through certain types of clays and earths (particularly fuller's earth) undergoes changes in chemical constitution and physical characteristics. Such filtration effects partial decolorization and a certain degree of fractionation. Light-colored, transparent, mobile oils of low specific gravity are thus derived by natural processes from comparatively heavy, viscous and dark-colored crudes. It seems probable also that many of the impurities found in petroleum are accumulated during its migration from scattered points of formation to the reservoir in which it is finally concentrated. Some authorities note an increased percentage of sulphur in the oil in certain regions as it travels farther from the rocks in which it was formed.

GEOLOGICAL STRUCTURES FAVORABLE TO ACCUMULATION OF PETROLEUM

It has been shown that the forces causing migration of petroleum tend to concentrate oil and gas in the upper horizons of folded porous strata, particularly in the crests of anticlines. The prospector is therefore attracted in his search by indications of anticlinal structure in any of its various forms. These include symmetric and asymmetric anticlines, domes, monoclines and terraces. Faults and unconformities are occasionally instrumental in isolating the rock fluids in parts of formations in such a way as to influence the accumulation of petroleum. Lenses of porous rocks in close association with carbonaceous shales offer favorable conditions for oil accumulation. Salt domes and volcanic "necks" have in some fields been responsible for accumulations of petroleum, owing to flexuring of strata into which they are intruded. An endless variety of combinations of these structural features present themselves in the geologic study of prospective oil fields.

Anticlines

Simple symmetrical anticlines, presenting ideal anticlinal conditions for the accumulation of petroleum (see Fig. 1), are seldom found in nature. Usually one

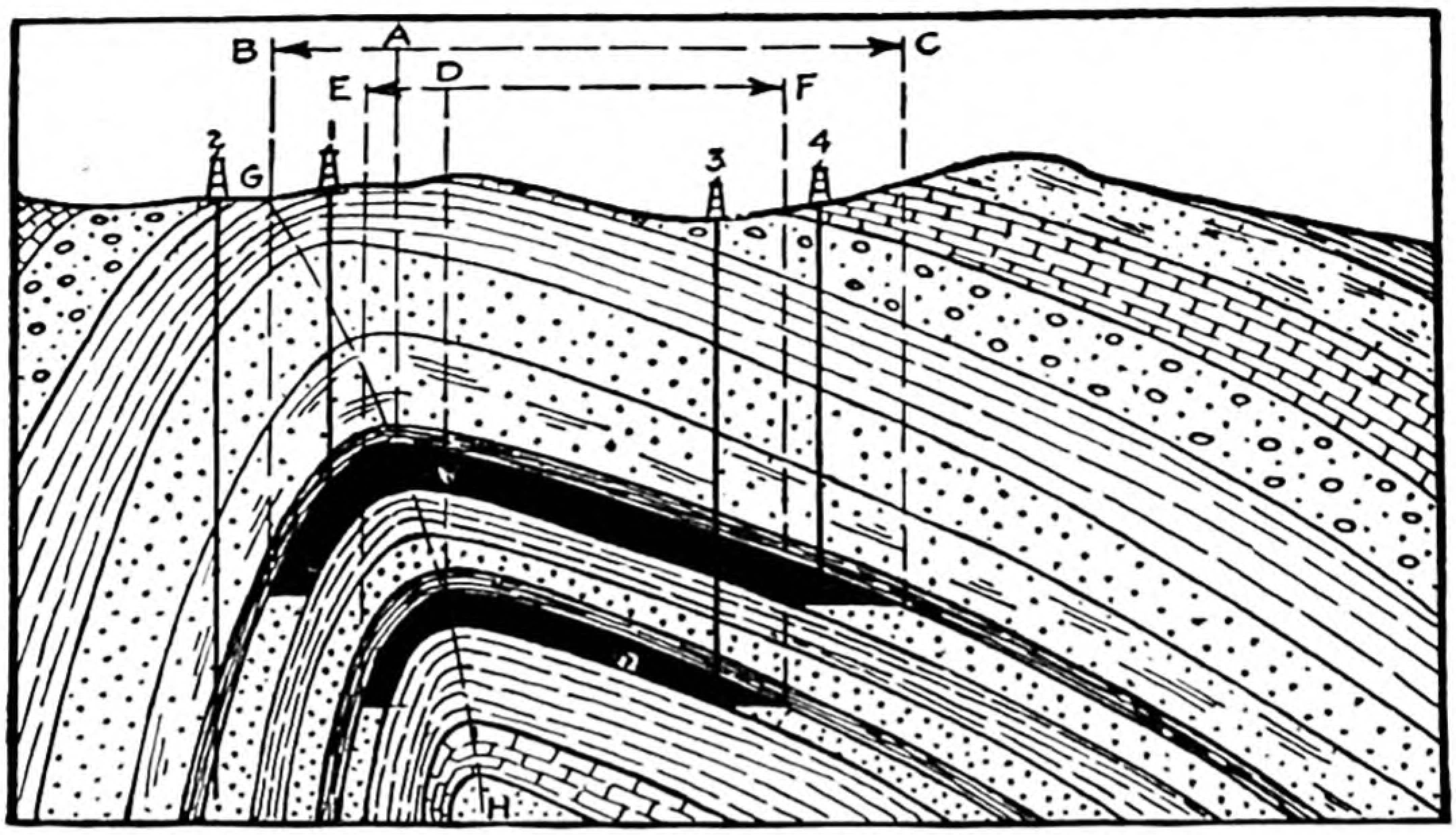
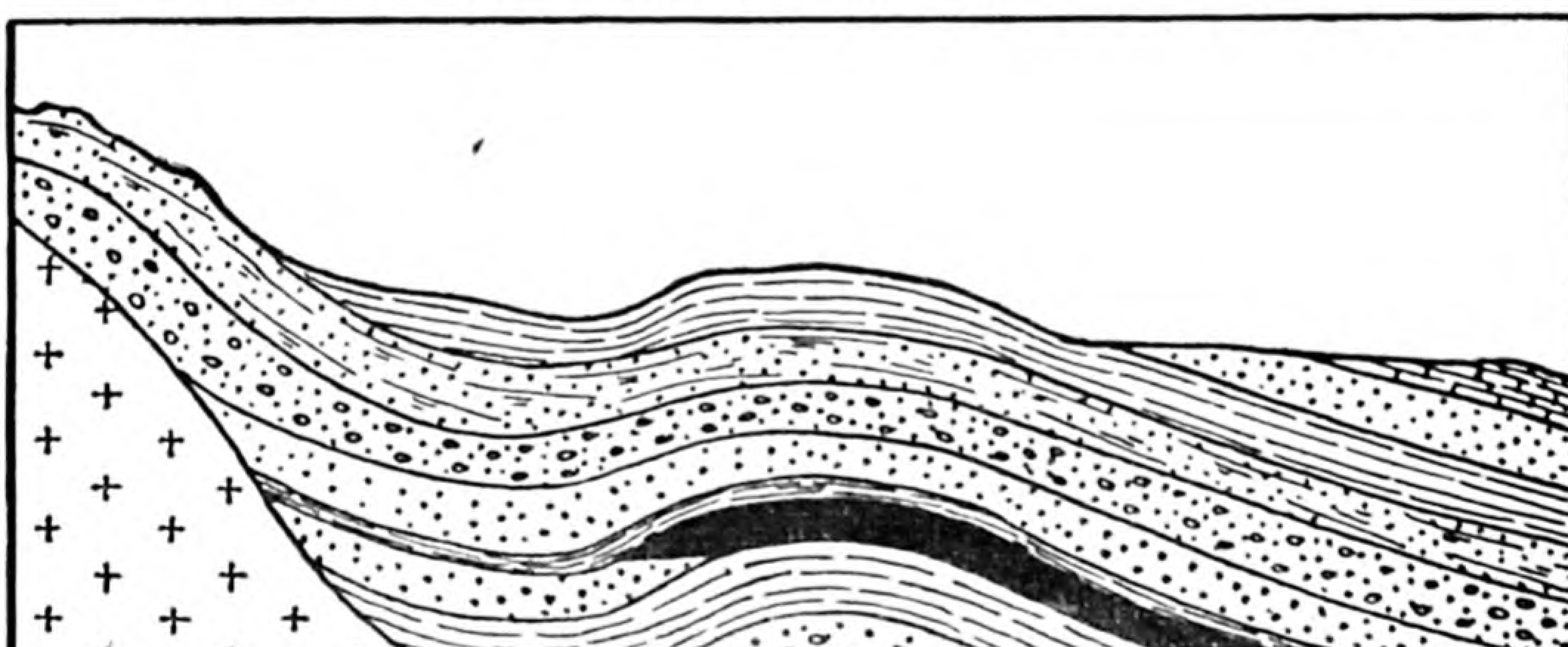


Fig. 2.—Illustrating a simple asymmetric anticline with two oil-bearing strata.

Note change in dip of axis of fold (line *G-H*). *B-C* indicates the width of the productive area for the upper sand, *E-F* that of the lower sand. Axes of folds (at *A* and *D*) lie near the left edge of the productive area. Well No. 1 is productive; No. 2, only a short distance away, is barren. Well No. 4 produces from the upper sand only, No. 3 from both upper and lower sands.



(*After W. H. Emmons.*)

Fig. 3.—An asymmetric anticlinal fold along the flanks of a major uplift, illustrating how greater accumulations of petroleum may be found on the basinward side of an anticline.

Note difference in level of the edge-water lines on opposite flanks of the anticline.

flank is steeper than the other, in which case the more common form of asymmetric anticline results (see Figs. 2, 3, 4 and 5); or the axis of the anticline plunges, *i.e.*, is not level (see Fig. 5). A common type of asymmetric anticline, known as "terrace structure" in certain fields, has one flank nearly vertical and the other inclined at only a

few degrees from the horizontal (see Fig. 4). Overturned folds and intense folding may result in exceedingly complex structures, often difficult to interpret from the field evidence.

It should be remembered that the axes of anticlinal folds are seldom straight lines but curve in both the horizontal and vertical planes (see Fig. 7). Where they curve

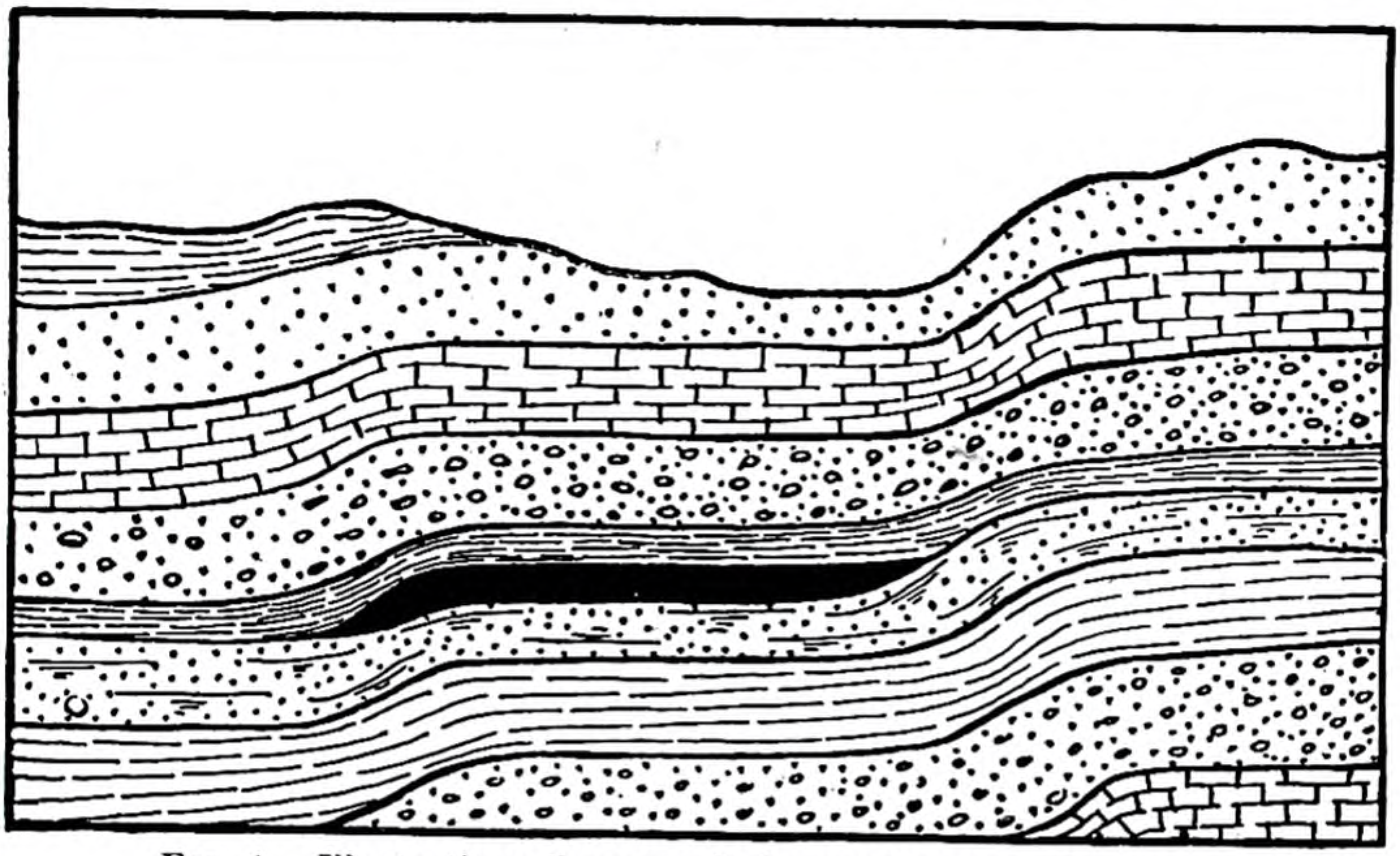
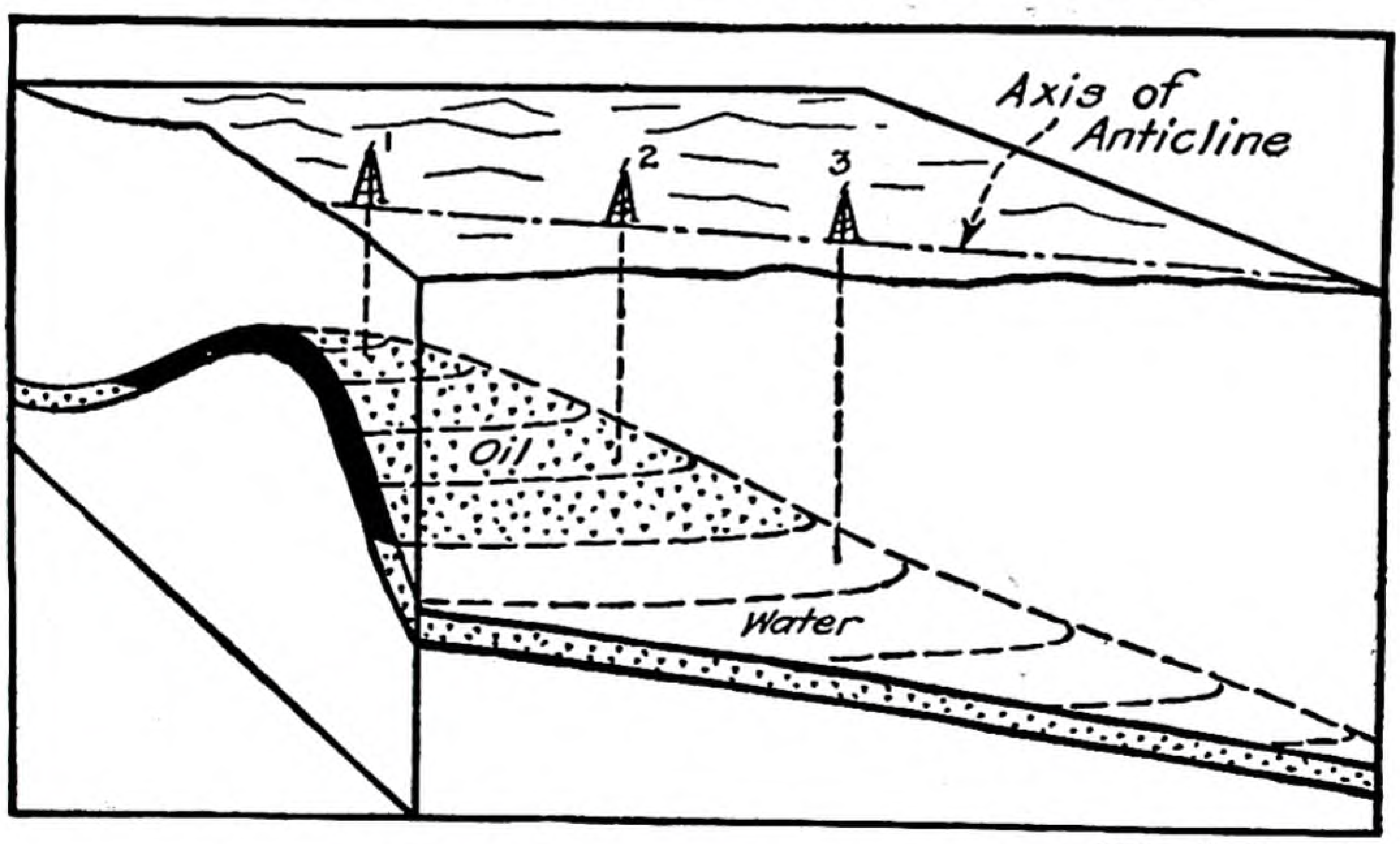


FIG. 4.—Illustrating oil accumulation on "terrace structure."



(*After D. Hager.*)

FIG. 5.—Stereogram of a plunging anticline.
Wells Nos. 1 and 2 are productive; No. 3 encounters edge water.

sharply, strata on the inside of the fold are compressed while those on the outside are put under tension, thus forcing the oil toward the outer flank, away from the point of greatest compression. Especially prolific concentrations of oil may be expected where a change in strike of the axis occurs and especially on the convex side of the fold.

Many anticlinal folds that are productive of oil occur along the lower flanks of major uplifts. The greatest accumulations of oil in such cases are generally found

on the basinward flank of the anticline, this side having the advantage of a greater area over which concentration of the oil has been operative (see Fig. 3). In some cases the three anticlinal zones, occupied by gas, oil and water respectively, will be

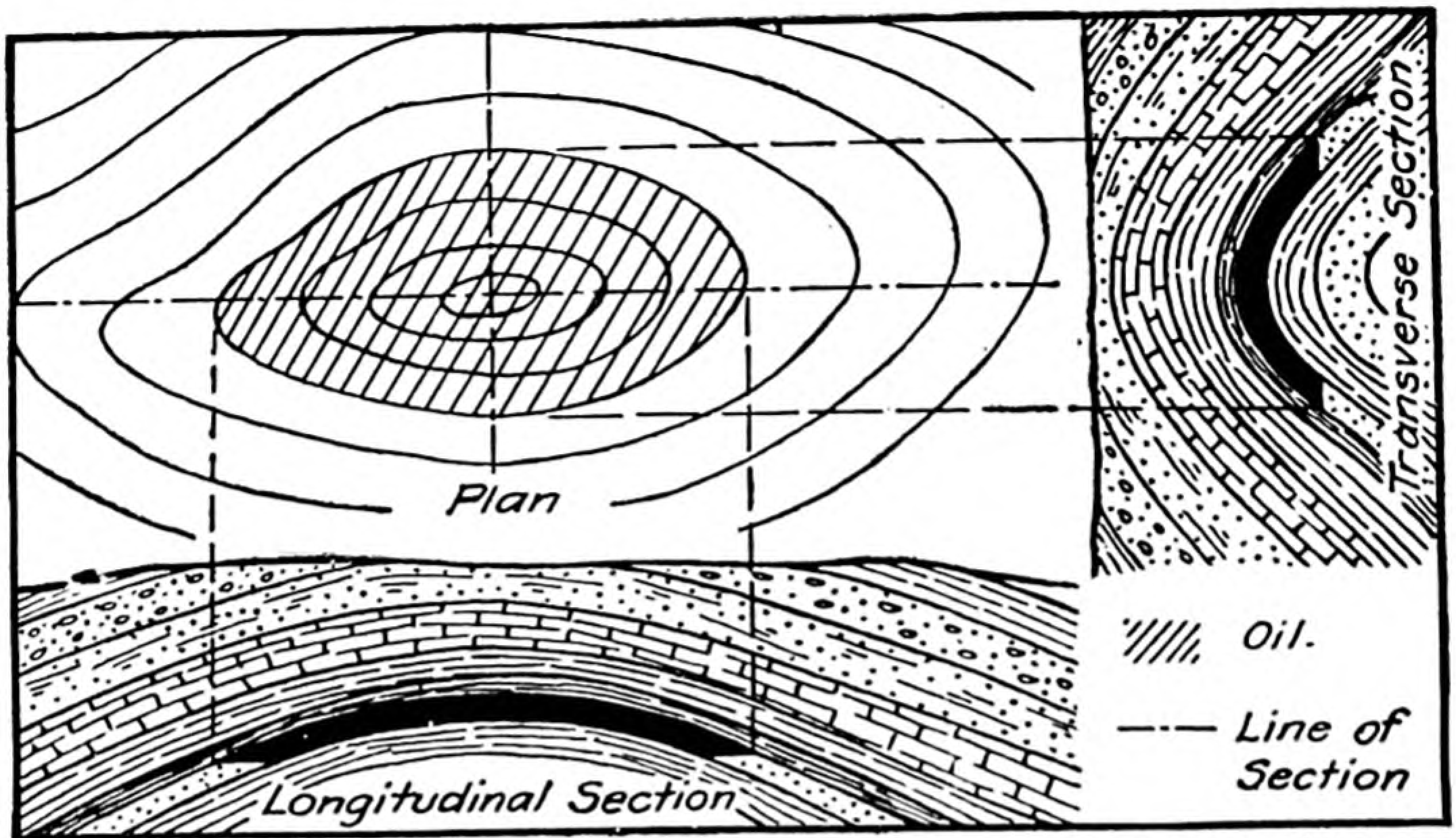


Fig. 6.—Dome structure illustrated in plan view by structure contours and by vertical sections through the major and minor axes.

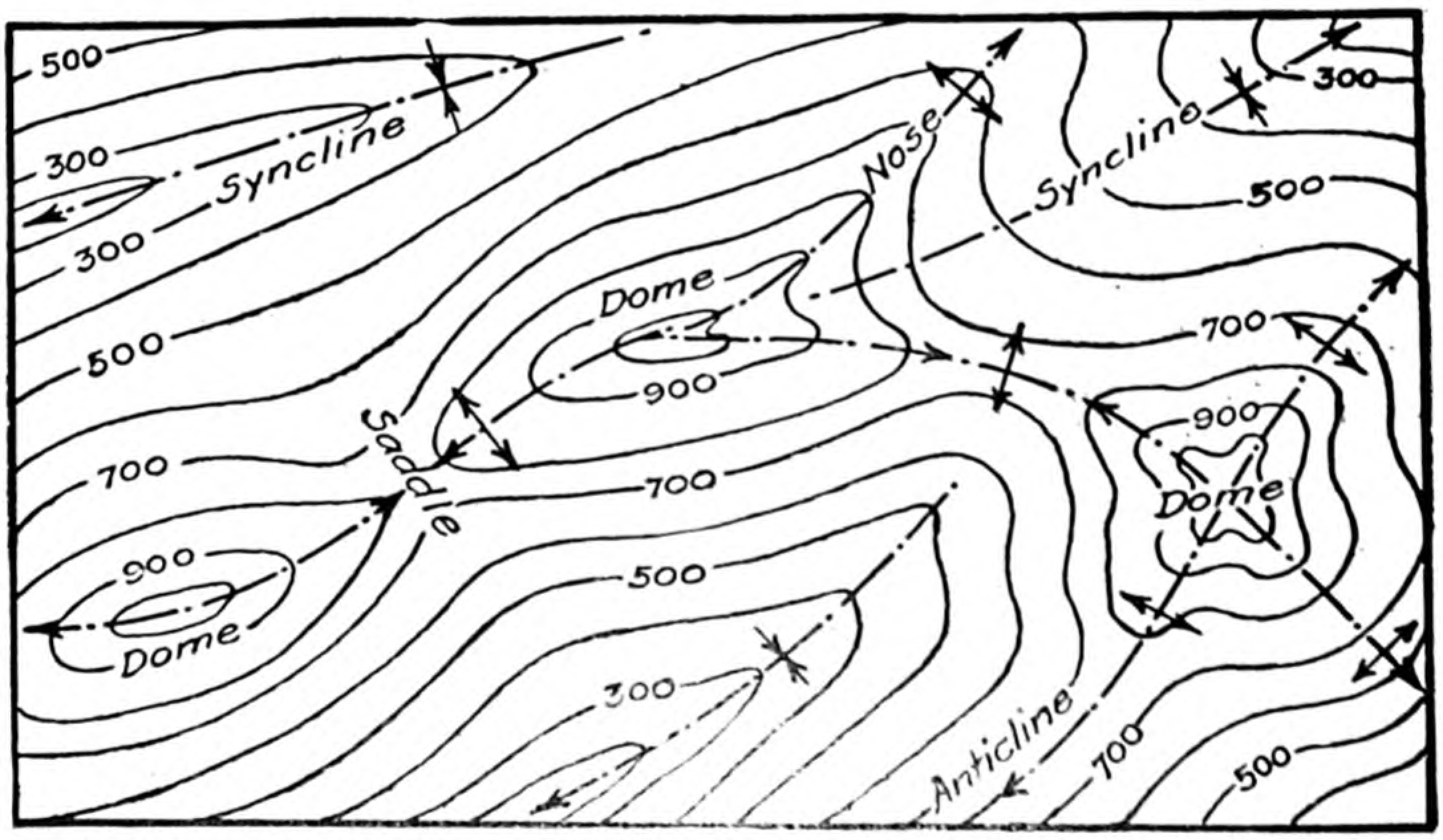


Fig. 7.—Structure contour map showing form of top surface of a producing oil sand and illustrating manner of indicating various structural features.
Oil accumulates under the three domes.

fairly well developed, with a well-defined "edge-water" line marking the limits of the oil "pool." In other cases, particularly in low-dipping strata, the oil and gas will be intimately associated in all parts of the productive zone, and the edges of the pool will produce mixtures of oil and water. The edge-water lines are often at different levels on opposite flanks of an anticline and may move up- or down-dip with changes in porosity of the containing stratum.

Domes

In the case of domes we have the conditions favoring high concentration of oil and gas best developed. The structure here dips off in all directions from a crestal point, and oil is concentrated from all flanks over the entire area of the dome toward its summit. Many of the most productive oil fields exhibit well-developed dome structure, and in nearly every case the highest concentrations of oil and gas are found at or near the structural crest.

Domes are of various forms (see Figs. 6 and 7). They are the result of two or more intersecting anticlines or of local variations in dip on the flanks of some larger

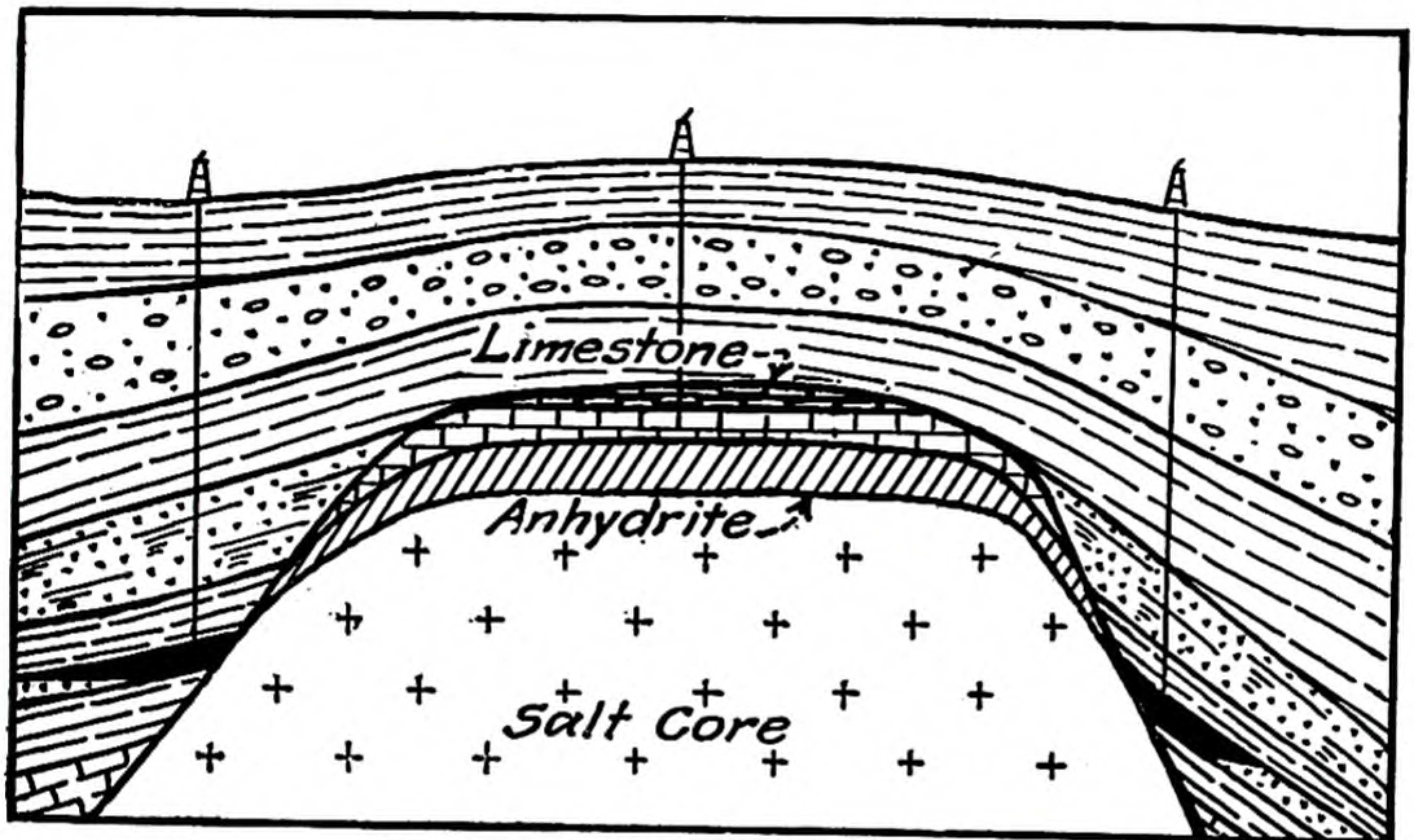


FIG. 8.—A typical salt-dome deposit.
Oil accumulates in porous formations above and on the flanks of the salt core.

fold. More rarely they are formed by pressure from below of intrusive igneous rocks, or as a result of pressure developed by the intrusion of large bodies of salt (salt domes, see Fig. 8). Popular usage does not clearly distinguish between what are sometimes called "elongated domes" and ordinary anticlines. All anticlines are long, narrow domes in the sense that they are closed structures, plunging or flattening out at each end where they merge with other structures. Hager[43] suggests that only closed structures in which the length does not exceed three times the width be spoken of as domes. The size of the trap down to the lowest closed contour will determine the maximum size of the pool that can accumulate, but only rarely is the "closure" a measure of the actual size of the pool. This is determined, rather, by the adequacy of the source material tributary to the trap. Sometimes, because of tilting of the structure, some of the accumulated oil is permitted to escape.

Monoclines

When the crest of an anticlinal fold is eroded away, a partial cross section of the strata making up the fold is exposed at the earth's surface and the undisturbed lower flanks form what are called "monoclines" (see Fig. 9). If one or more of the outcropping strata contain oil, the nature of the material will be made evident by accumulations of oil and bituminous materials along the outcrop. The upward pressure of gas and the hydrostatic head, still operative in the oil-bearing strata,

tend to force the oil out of the sands, accumulating it in pools on the earth's surface, from which it evaporates or is carried off by the natural water courses. Wastage of oil, as a result of erosion of anticlinal crests and exposure of oil-bearing strata, has undoubtedly been responsible for the dissipation of much of the petroleum accumulated by nature's processes in former geologic periods. Fortunately, if the deposit is a large one, the oil is capable, by reason of its own physical properties, of sealing the outcrop and preventing escape of the oil originally stored in the lower flanks of the fold. This is accomplished by evaporation of the lighter and more volatile con-

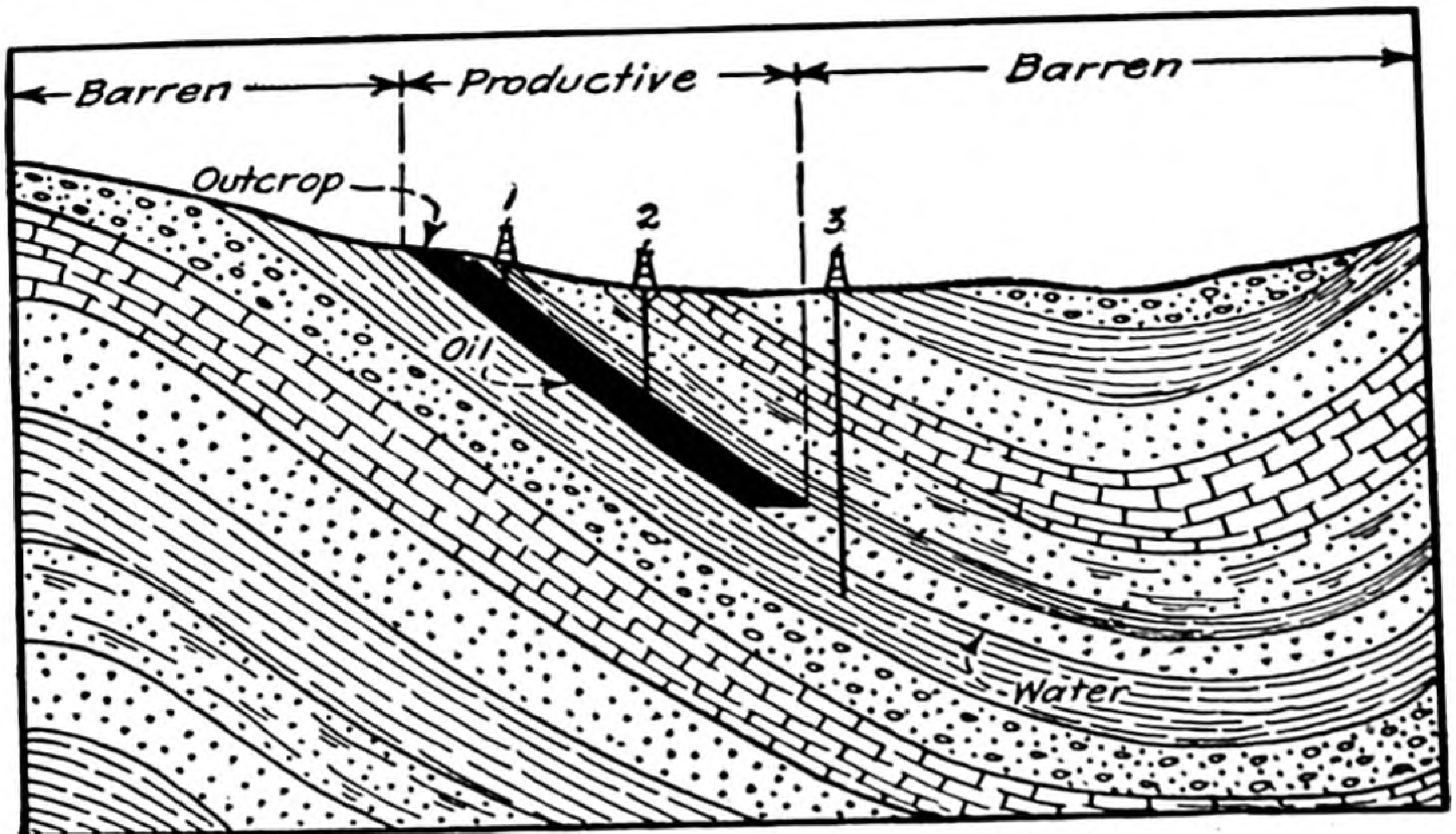


FIG. 9.—Illustrating simple monoclinal structure.
The shallow well, No 1, produces heavier, more viscous oil than No. 2 owing to evaporation of the lighter constituents at the outcrop. Well No. 3 encounters edge water.

stituents of the oil, leaving in the surface rocks a residual product of solid paraffin or asphalt which completely closes the rock pores and prevents further migration from below. The remnants of oil deposits, so exposed and yet protected from further loss, are readily located by their prominent bituminous outcrops, are easily developed and serve as important sources of petroleum in some fields.

FAULTS

Faulting, being the result of the same earth forces that bring about folding of strata, is often in evidence in oil-bearing formations and must be considered as a factor in oil accumulation. A fault may intersect an oil deposit and so displace one portion with respect to the other that for all practical purposes they become separate deposits (see Figs. 10 and 11). Faults sometimes fracture a porous monoclinal stratum, formerly barren of oil, and interpose a stratum of impervious clay or shale across the faulted face in such a way that a structural trap is formed in which oil may subsequently be concentrated. It is commonly supposed that faults provide channels of communication between strata originally separated from each other by impervious beds. Fluids may thus be transferred from stratum to stratum across fault planes, perhaps dissipating accumulations of petroleum through great thicknesses of formerly barren rock. Although the influence of faults on oil accumulations must always be somewhat problematical, they constitute a disturbing structural feature which the prospector must take into account in locating test wells.

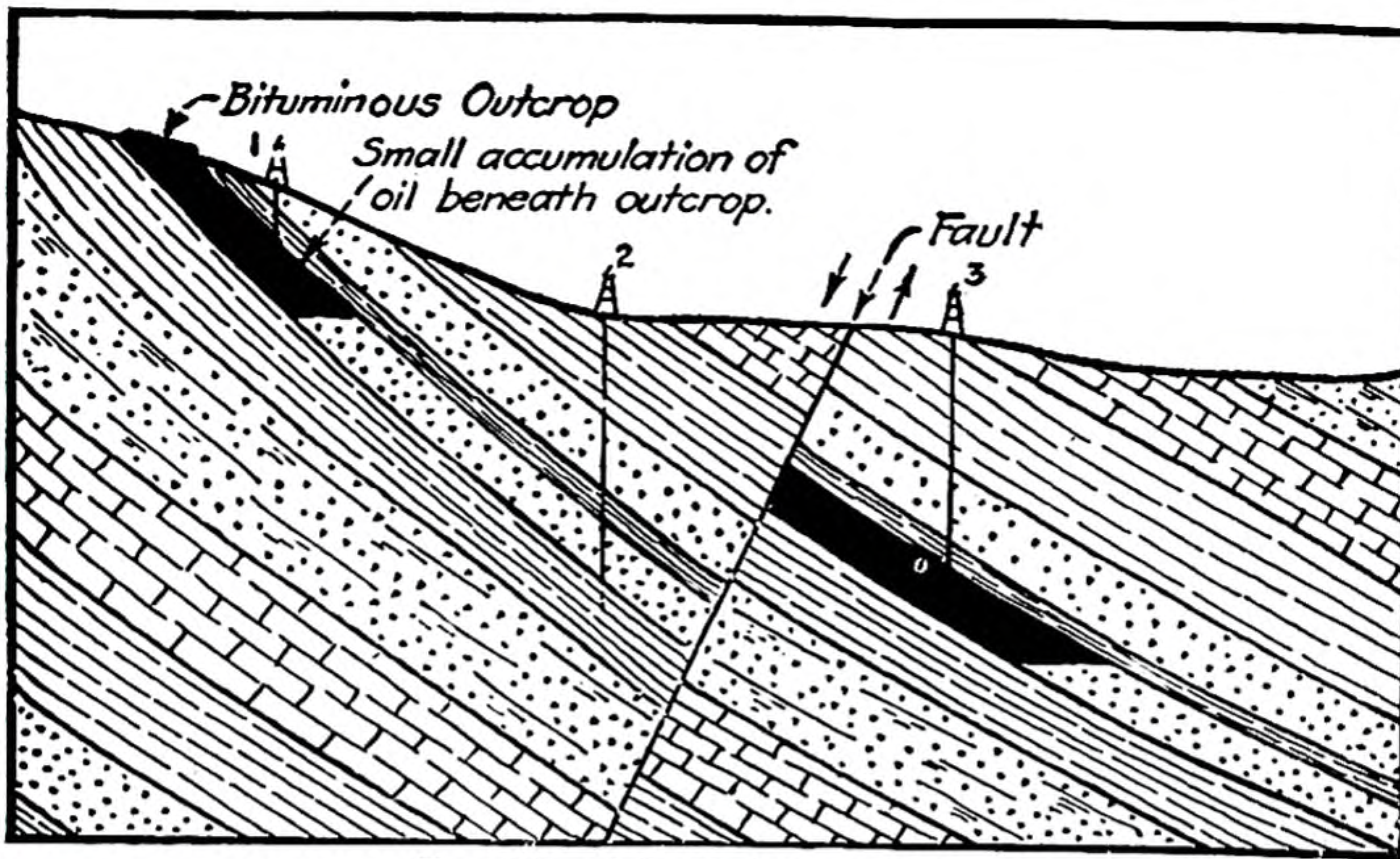


Fig. 10.—A faulted monocline.

The illustration shows how a fault may interpose an impervious stratum across the lower part of an oil-bearing stratum, permitting accumulation of a deposit of petroleum, which is sealed by the fault "gouge" and prevented from escaping up the dip of the structure. Wells Nos. 1 and 3 are productive. Well No. 2, halfway between, encounters edge water.

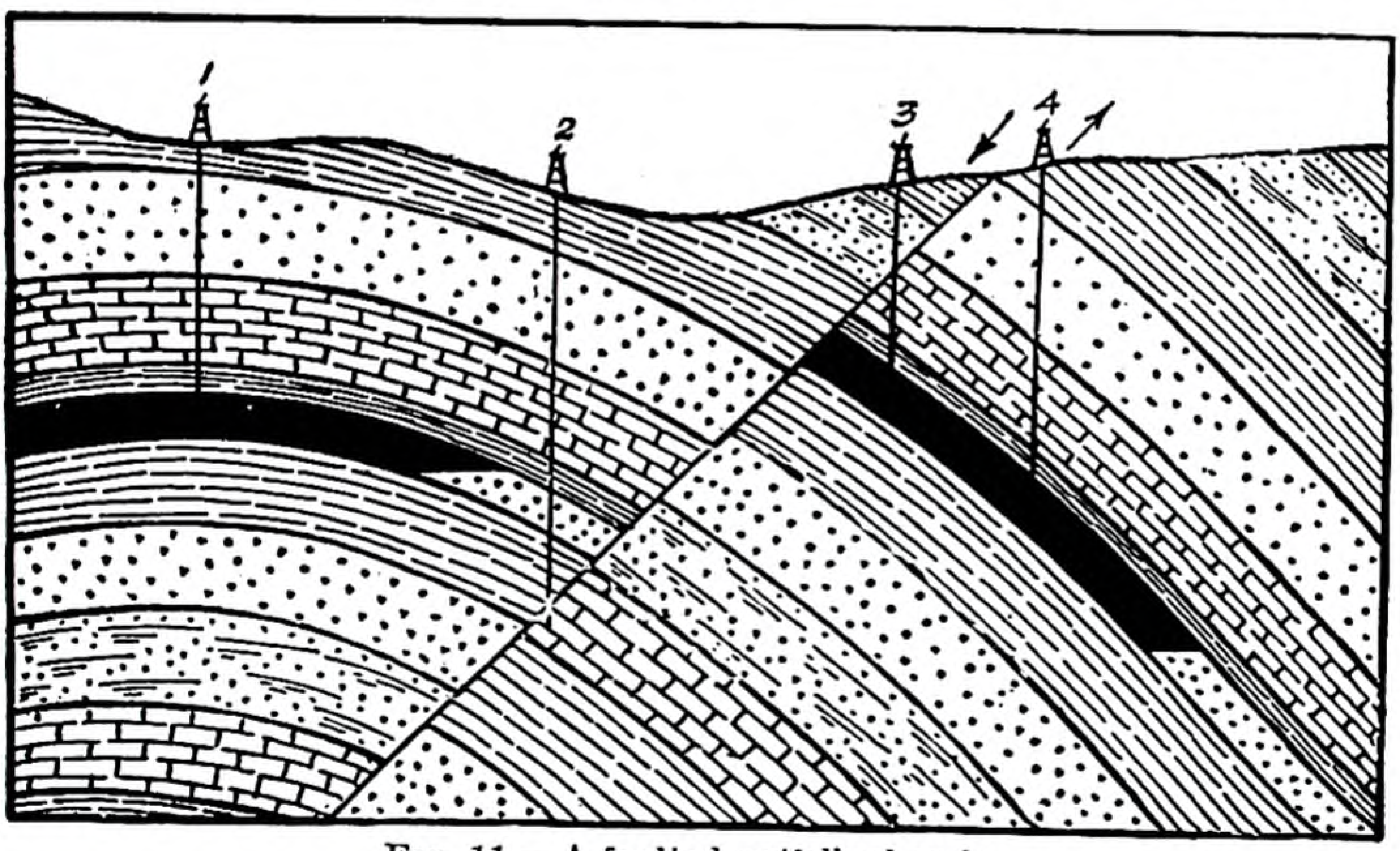


Fig. 11.—A faulted anticlinal arch.

The figure illustrates oil accumulation on both the up-throw and down-throw sides of a fault, and shows how faulting may leave barren places in anticlinal structure. Wells Nos. 1, 3 and 4 are productive; No. 2 encounters edge water; No. 3 intersects the fault plane.

Unconformities

A period of erosion, perhaps accompanied by tilting and folding, may intervene between two periods of deposition and leave the accumulations of the two periods unconformable at their surface of contact. Strata of the older series may thus dip at entirely different angles from those of the younger series. Sealing of porous beds of the lower series by impervious layers of clay or shale at the base of the upper series may provide favorable conditions for the accumulation of petroleum in the older rocks against the unconformity (see Fig. 12). In other cases oil originating in the lower

formation may flow along and across the unconformity, accumulating in upper strata only remotely related with those in which the oil was originally stored. Compaction of sediments deposited on an eroded surface possessing considerable relief will sometimes result in the younger beds developing dips roughly conformable with the eroded

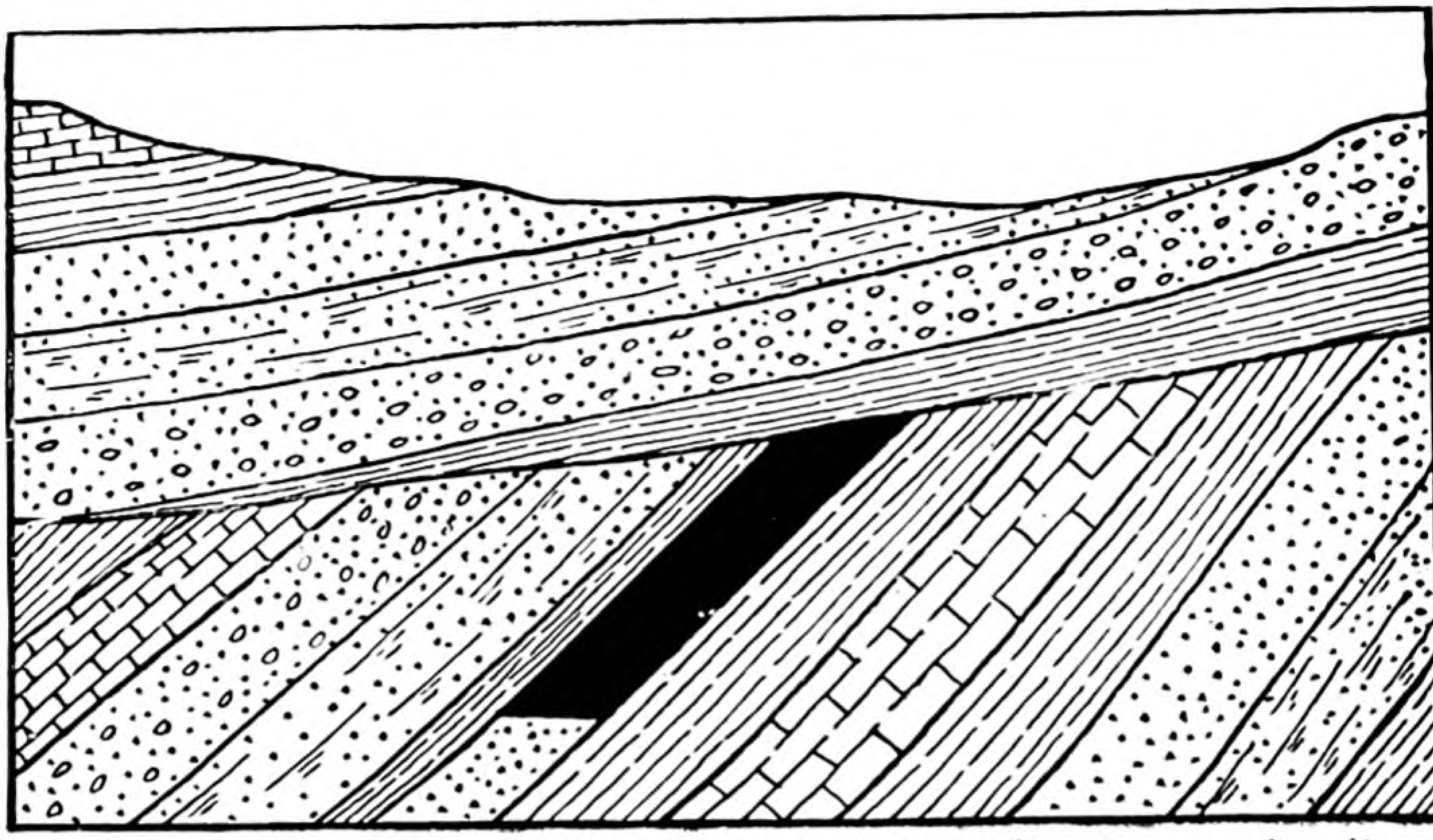


FIG. 12.—Illustrating accumulation of petroleum against an unconformity. The impervious stratum at the base of the upper series prevents escape of the oil.

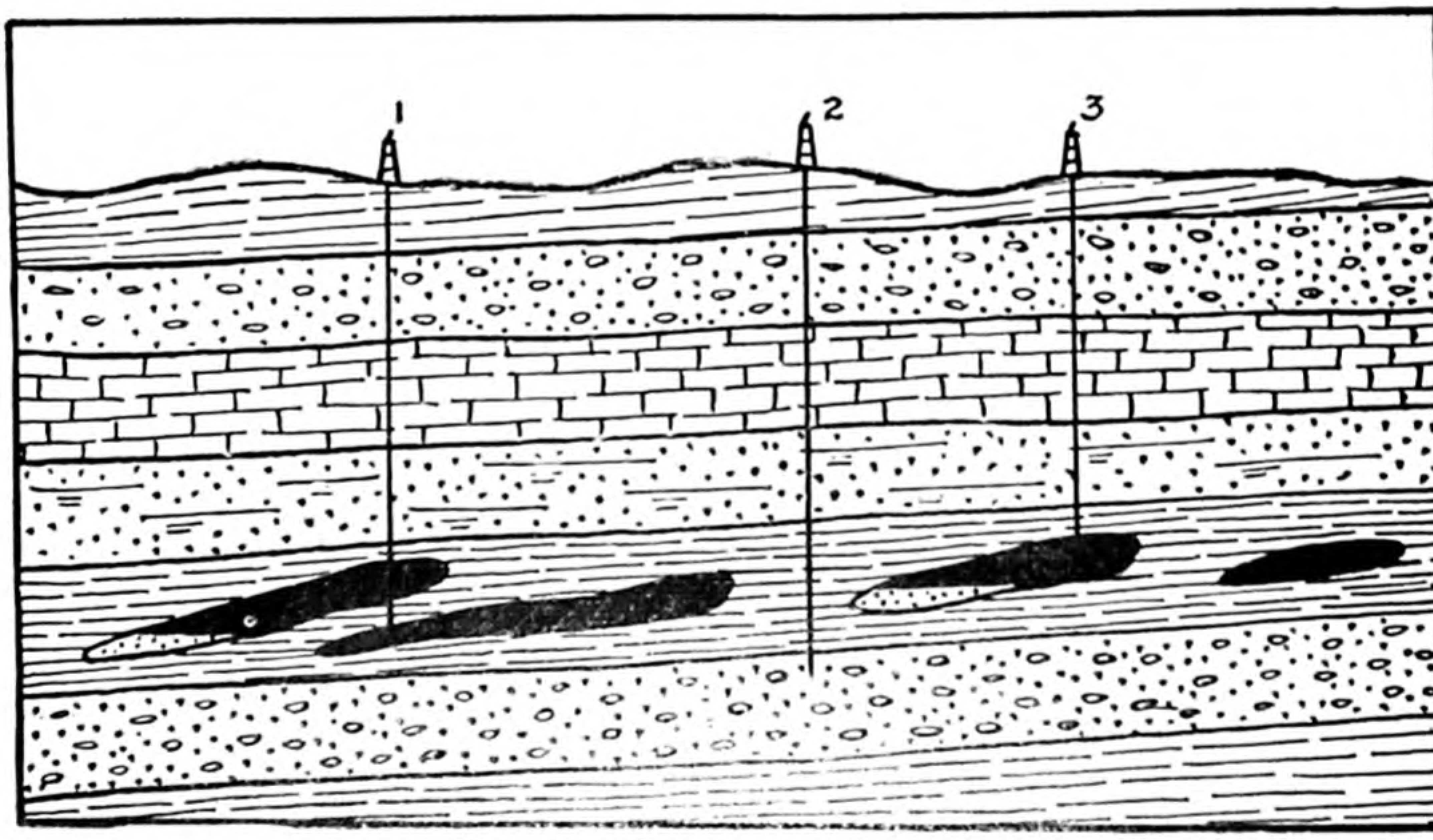


FIG. 13.—Lenticular deposits.

Lenses of coarse sand embedded in oil-bearing shales serve as local centers of concentration. Well No. 1 produces from two lenses, No. 3 from only one. Well No. 2, between No. 1 and No. 3, is unproductive.

surface of the older formations. Petroleum originating in the younger beds may thus migrate up the dips thus created, accumulating against the flanks of the "buried hills" and ridges of the old erosion surface. So-called "buttress structures" are of this type. Such conditions are exceedingly difficult to decipher in the field, and surface structural studies will be of little assistance in working out the true situation.[50]

Lenticular Deposits

Lateral variation in oil-bearing strata, particularly in sands and sandstones, is often responsible for marked changes in the oil content of strata at different points (see Fig. 13). This is due to variation in character of grain structure, cross-bedding and other irregularities resulting from the manner of original deposition of the containing rock. The result is a succession of lenses of porous sands embedded in relatively close-grained rocks, the whole forming what is apparently one continuous, fairly well-defined stratum. Oil naturally seeks out the porous lenses in which to accumulate, leaving the less porous rocks comparatively barren. In general, the major concentrations would be influenced by anticlinal structure in such a lenticular stratum, but surprising differences in saturation of the sands will be in evidence. Perhaps the crest of the structure, which would ordinarily be selected as the best site for a test well, will be almost barren, while an apparently less favorable position, with respect to the structural evidence, will be highly productive. Such conditions can scarcely be taken into account in geological surveys for the location of test wells and constitute one of the inherent uncertainties with which the oil prospector must contend.

It has been stated that the original organic material from which petroleum is derived was probably deposited in sedimentary marine strata in shallow waters along the shores of bays and lagoons. Most sedimentary strata are laid down against shore lines, and any cross-bedding that might be developed, as well as any segregation of coarse and fine detritus during deposition, would be roughly parallel with the shore line against which it has been formed. It follows that the lenses or channels of relatively porous sands in which petroleum later accumulates should be approximately parallel to the shore lines of the period in which they were formed. Field evidence shows this to be generally true. The location of ancient shore lines is therefore of assistance to the petroleum prospector in aiding him to predict the probable trend of lenses and channels that are responsible for unequal distribution of petroleum in the containing stratum.[39]

Stratigraphic Traps

A type of oil and gas accumulation, resulting from irregularities in bedding and depending to but a limited extent on structural conditions, is classified under the general designation of "stratigraphic trap." Mere lateral variation in porosity or "pinching out" of reservoir strata between converging impermeable beds, with inclination of strata but not necessarily with closed structure, will provide opportunity for segregation and accumulation of gas and oil in the upper part of the porous portion of the reservoir strata.[48]

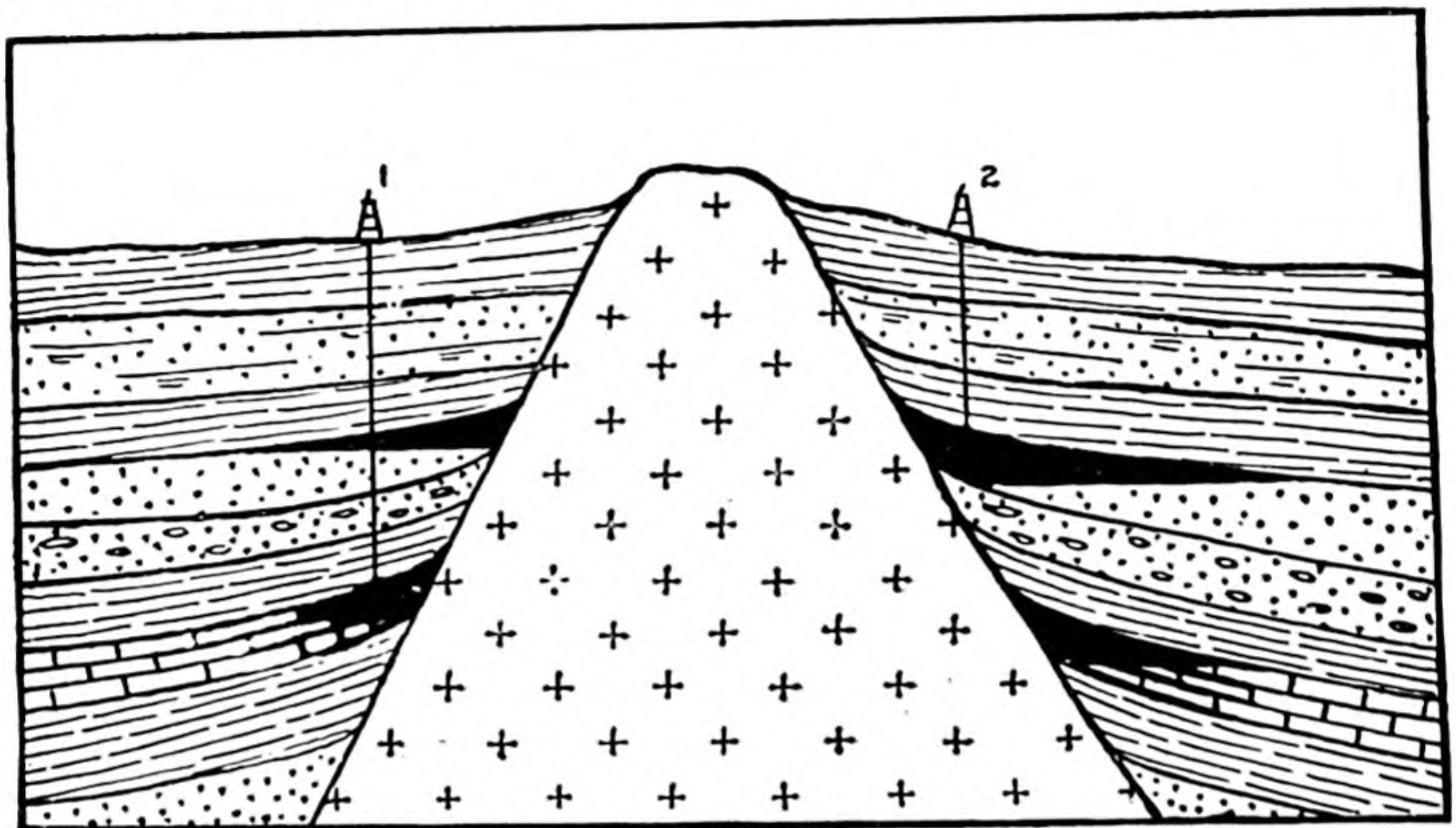
Salt-dome Deposits

In portions of the Gulf Coast region of the United States, in Germany and in various other oil-producing regions, petroleum is found in close association with deposits of salt (see Fig. 8). These salt masses are largely anhydrite, but replacement processes often provide the salt mass with a gypsum or dolomite capping. The salt deposits have been responsible during their accumulation for considerable upward pressure, resulting in doming of the overlying sedimentary rocks. It is considered probable that these salt masses were intruded into the sediments in which we now find them, salt flowing as a viscous semisolid when subjected to high pressure. Doming of the sedimentaries has in many cases effected concentration of petroleum origi-

nally disseminated through the surrounding formations so that it accumulates within the upturned porous beds about the summit and flanks of the salt core. Upward of a hundred salt domes have been found in the Gulf Coast area of the United States, and the sedimentary strata about them have in many cases been found to be productive of petroleum in commercial quantities.[37,46]

Petroleum Deposits in Association with Volcanic Intrusions

In certain Mexican fields petroleum is found in sedimentary strata, the edges of which have been folded up along the flanks of volcanic necks (see Fig. 14). Apparently in such cases the intrusive igneous rocks have merely been responsible for the



(*After F. G. Clapp.*)

Fig. 14.—Illustrating occurrence of oil on the flanks of an intrusive volcanic neck

Oil accumulates in upturned edges of porous sedimentary rocks. Well No. 1 may produce oil from two horizons, while No. 2, located nearer the intrusive contact, produces only from the upper horizon.

development of folds into which oil has migrated from the surrounding sedimentary formations. Such deposits are rare and do not constitute any exception to the universal derivation of petroleum from sedimentary rocks.

SURFACE INDICATIONS OF PETROLEUM

The attention of the prospector is often attracted by surface indications which have come to be regarded as indicative of the presence of petroleum. These include oil seepages, hydrocarbon gas emanations, bituminous outcrops and deposits of asphalt and paraffin waxes. In addition to these positive indications of petroleum, there are other occurrences which do not necessarily indicate the presence of petroleum but which are often associated with oil deposits. Salt and brine, sulphur and sulphurous waters and gases, acid waters, oil shale and burnt shale are commonly regarded as offering corroborative but not conclusive evidence.

Oil Seepages.—Oil seepages offer the most direct evidence of the presence of petroleum. In places where oil-bearing rocks outcrop at the surface or where the

cap rocks overlying an oil deposit have been fractured, oil may come to the surface as "oil springs" or may accumulate in pools along the outcrop or fault plane. The flow of oil is seldom copious because of the tendency of petroleum to seal such outlets by the accumulation of solid hydrocarbons resulting from evaporation of the lighter liquid constituents. Petroleum escaping in this way, even in minute quantities, will often make its presence known by the formation of iridescent films on water in ponds, wells, springs and streams. This film, which is quite characteristic, somewhat resembles that formed by oxide of iron, but the latter will be readily distinguished by its brittleness. The oil film is cohesive and persistent and displays a peculiar tendency to disperse on the water surface when brought into contact with a little ether vapor or with a drop of ether on the end of a glass stirring rod.

Hydrocarbon Gases and Related Phenomena.—Because of their common association in nature, hydrocarbon gases are also significant indications of the presence of petroleum. Cap rocks may be sufficiently impervious to prevent oil seepages from reaching the surface, but the slightest crevice or joint plane will serve for the passage of gas. Hydrocarbon gases, being colorless, are not so conspicuous as oil seepages, but their presence is often made apparent, when associated with oil, by their characteristic petroleum odor. They burn readily and are explosive when mixed with proper proportions of air.

The petroleum odor of hydrocarbon gases associated with oil deposits is often masked by the stronger odor of hydrogen sulphide and sulphur dioxide with which they are sometimes contaminated in nature. The characteristic odor of ammonia is occasionally observed in gases associated with petroleum. Rogers* has suggested that ammonia may be derived from naturally occurring ammonium compounds, such as ammonium sulphate, by contact with hydrocarbons in either the liquid or the gaseous phase. Interreaction of the two sulphur gases with water sometimes results in the formation of native sulphur in the form of a sublimate about the openings through which the gases escape. Sulphuric acid similarly formed may give the ground waters of the locality a slight acid reaction. Rogers also suggests that sulphur and sulphur compounds are in many cases derived from sulphates by the reducing action of hydrocarbons. Anaerobic bacteria that may exist in ground waters associated with crude petroleum throughout long periods of time have been shown to have the power of converting sulphates into sulphides. Pyrite, though often present in rocks associated with oil and gas, is not considered as an indication of petroleum. The presence of sulphur and sulphur gases cannot be regarded as more than corroborative evidence, since they are often formed by reactions which are not in any way related to the occurrence of petroleum. Even hydrocarbon gases are not infallible evidence, as "marsh gas," which is chiefly methane, is often found where oil is not. If the gases are "wet," that is, if they contain condensable hydrocarbons as well as methane, the presence of liquid petroleum in association with the gas is more definitely assured.

When escaping through argillaceous rocks at the earth's surface, gases have a tendency to build up clay mounds about the openings through which they issue. These accumulations, generally in the form of a cone, are called "mud volcanoes." They vary greatly in size from small mounds to hills covering many acres and simulate on a small scale all the characteristics of true volcanic activity. On erosion, the crevices on which the mounds accumulate may become filled with mud and form mud dikes. Mud volcanoes and mud dikes prominently mark the position of gas "seeps" in some oil fields.

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* Rogers, G. S., Chemical Relations of Oil Field Waters in the San Joaquin Valley, California, *U. S. Geol. Survey, Bull.* 653, 1917.

Bituminous Outcrops.—When liquid hydrocarbons are subjected to contact with air, evaporation of the lighter constituents leaves a solid residue of asphalt or paraffin wax. Oxidation of the heavier hydrocarbons is also a factor in this process of solidification. The sandstones in which these solid hydrocarbons are deposited become tough and resistant to weathering and disintegration, forming prominent bituminous outcrops where the oil-bearing strata intersect the surface. These bituminous deposits are quite characteristic and in many fields have attracted the attention of prospectors to the particular strata with which they are associated. In some instances deposits of liquid petroleum are found in monoclinal structures a few hundred feet down the dip of the strata below the outcrop. In other cases, bituminous sands are apparently merely remnants of former oil deposits that have been eroded away. In any case, however, they prove in no uncertain manner that the strata in which they occur are petroliferous, and they may serve to focus attention on their particular horizon in anticlinal structures in the vicinity where sealed deposits of petroleum may be found.

If the bituminous material has been subjected to prolonged weathering and oxidation, only traces of the petroleum formerly present will be in evidence, occasionally so little that resort must be had to the acetone test or to solution tests with one or another of the various oil solvents to disclose its presence; or a closed-tube distillation test may be applied. In the latter, a little of the dried and powdered material heated to redness in the closed end of a glass tube will yield oil vapor which condenses near the open, cold end of the tube as a yellowish white or brownish "fog" or in small drops. Black manganese oxide often stains a sand or sandstone so that it apparently contains a carbonlike residue, but it is readily distinguished when the solvent and heat tests are applied. Certain carbonate waters and other aqueous solutions, containing in suspension finely divided and concentrated organic residues of vegetable origin, closely resemble petroleum in general appearance but have none of its specific properties.

Mineral Waxes.—The mineral waxes, particularly gilsonite, grahamite, albertite and ozocerite, are derived directly from liquid petroleum by segregation of the lighter constituents. They are commonly found in veins or fissures and are often spoken of as "intrusive" petroleum. Such deposits are sometimes directly connected with deposits of liquid petroleum and in any case serve as conclusive evidence of the petroliferous character of the rocks in which they are found. Outcrops of such veins, or even fragments of mineral wax resulting from erosion of wax deposits, are therefore of interest to the prospector for petroleum.

Bituminous Shales.—Deposits of carbonaceous shale containing "kerogen" from which an oil may be derived by natural processes, though offering no definite assurance that oil is present in association with them, are nevertheless indications that the prospector cannot afford to ignore.* When raw material from which petroleum may be derived is known to be present in the region, a search for localities in which the conditions are favorable for the necessary metamorphosis and accumulation may result in the location of deposits of liquid petroleum.

Strata containing bituminous shales have in some cases become ignited—perhaps spontaneously—and all or most of the carbonaceous material has been consumed, leaving hard, resistant layers of "burnt shale." Such shales are usually highly colored

* The "pyrobitumens" do not, as a rule, respond to the solvent tests described above and must be heated before their carbonaceous character becomes evident. A little of the powdered material, heated to redness in a glass tube closed at one end, will yield oil vapors which condense on the walls of the cold end of the tube. The odor of these vapors is quite characteristic.

by red oxide of iron and, because of their hardness and resistance to weathering, often form the crests of prominent ridges and "tables." Even though they are no longer carbonaceous, the knowledge that they were so at one time may be suggestive to the prospector in searching for localities which might have escaped the destructive agency, or for localities in which hydrocarbon vapor might have condensed forming deposits of petroleum.

Saline Ground Waters.—Knowledge of the universal association of salt water with petroleum stimulates interest on the part of the prospector in all brine springs and deposits of salt. Such occurrences, however, are very common in nature and are not necessarily indicative of the presence of petroleum. They are to be regarded at best as nothing more than corroborative evidence to substantiate predictions based on other and more positive indications.

"Paraffin Dirt."—In the vicinity of the salt domes of the Gulf Coast region, the surface soil contains quantities of a yellow, waxy substance resembling paraffin or beeswax, which has been given the name of "paraffin dirt." It is thought by some oil prospectors to be indicative of the presence of petroleum in the vicinity, and that it has the same significance as a gas seep. Some salt domes have been discovered as a result of the occurrence of paraffin dirt in the surface soil.

Stunted Vegetation.—The effect of petroleum present in surface soil is detrimental to the growth of vegetation. Plant life in such soils is either entirely lacking or is stunted. So marked is this influence in regions where vegetation is ordinarily prolific that in certain instances attention has been directed to the soil, which on examination has been found to contain traces of petroleum. Since plant life may be absent for many other reasons than the presence of petroleum in the soil, such an occurrence is of only slight significance.

Table V.—Geologic Age of Petroleum Deposits

Era	System	Petroliferous character
Quaternary	Recent Pleistocene	Generally unproductive.
Tertiary or Cenozoic	Pliocene Miocene Oligocene Eocene	Generally asphaltic base petroleums. Tertiary formations produce more than half of the world's petroleum.
Mesozoic	Cretaceous	
	Jurassic Triassic	Generally unproductive.
Paleozoic	Permian Carboniferous Devonian Silurian Ordovician Cambrian	Generally paraffin base petroleums.
Proterozoic	Keweenawan Amikean Huronian	Unproductive.
Archeozoic	Archean	

GEOLOGIC AGE OF PETROLEUM-BEARING ROCKS

Paleontological classification of occurrences the world over indicates that petroleum is not confined to any one geologic period but occurs in rocks ranging from the Cambrian to the Recent (see Table V). Although petroleum is thus distributed through a considerable portion of the geologic column, it is found that the more prolific horizons may be classified within narrower limits. Existing evidence indicates that commercial-oil pools are confined to areas of unmetamorphosed rocks of Ordovician or younger age. Periods of greatest productivity are the Tertiary, Cretaceous, Carboniferous and Ordovician. Less productive formations occur in the Jurassic, Devonian and Silurian. Periods of comparatively small productivity include the Quaternary, Triassic and Cambrian. However, the occurrence of an oil pool will depend not so much upon the period during which the oil originated as upon the nature and geologic history of the sediments.

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CHAPTER II

PETROLEUM EXPLORATION METHODS

Exploration for new supplies of petroleum to replace the ever-waning production from known fields is an important phase of the petroleum industry. Although often regarded as a separate and distinct activity, petroleum exploration is a subject so closely related with field development that the engineer engaged in oil-field work must have general familiarity with its problems and methods. The detailed application of exploration principles and methods is properly entrusted to petroleum geologists specializing in this kind of work, but the petroleum engineer carries on the exploration of oil fields from the point where the geologist stops and each must be in some measure familiar with the methods of the other. Accordingly, this chapter is introduced, not with the purpose of attempting a thoroughgoing dissertation on the subject of petroleum exploration, but rather as an outline such as the production engineer requires in familiarizing himself in a broad way with the methods by which new oil fields are discovered.

GEOLOGY THE PRINCIPAL KEY TO OUR UNDISCOVERED OIL RESOURCES

In the previous chapter, it was shown that petroleum is found only where geologic structure is favorable and that it is confined for the most part to definite horizons and certain types of rocks. Accordingly, the principal effort of the petroleum exploration geologist is directed toward the identification of structure and lithology in geologic horizons and formations known to be promising. Petroleum is apparently found only in sedimentary formations younger than those formed during Proterozoic time and, for the most part, within the Tertiary and Paleozoic eras of the earth's history. The geologist therefore gives particular attention to areas in which formations representative of these periods are to be found within reach of the drill. In such areas he seeks to discover a source rock which may conceivably have furnished an organic parent material. His interest then attaches to any related porous formations, suitably capped, which might serve as a reservoir rock. If, then, an area can be found in which these formations are suitably folded into anticlinal forms, favorable conditions for the accumulation of petroleum are disclosed. It is also the task of the geologist to indicate the acreage within the favorable area which would probably be most

valuable from a development and production standpoint and to select the positions for such test wells as will be necessary to determine whether or not commercial production of petroleum may be realized.

Regional Reconnaissance

The geologist is often attracted to particular localities by reports of surface indications of the presence of petroleum, such as have been described in Chap. I. These will prove the presence of petroleum in rocks of a particular horizon; however, they do not necessarily indicate the presence of oil in commercial amounts. They may be remnants of some earlier deposit, the major part of which has been dissipated by erosion and degradation of the structure in which it was originally stored. Conditions in the locality may never have been favorable for an accumulation of commercial proportions, and such surface signs as are in evidence may be merely the result of small local concentrations. A well-defined anticlinal or domal structure in the locality of such an occurrence, however, would doubtless be of great interest to the geologist.

Most of the significant surface occurrences in the more accessible regions have already been investigated, and the geologist in his search for new oil deposits must usually be guided by much less definite indications. Interest may attach to an entire region in which rocks of suitable age, known to be productive elsewhere, are present in formations of appropriate thickness and at reasonable depth. The geologist's principal effort will then be directed toward identification and study of any structural features within the region that may seem favorable.

Before entering the field for a regional reconnaissance, the geologist should gather and carefully scan all geologic and topographic information available on the area to be studied. This may be in the form of geologic reports, technical papers or topographic maps. Government and state reports and maps and publications of geologic societies and scientific journals will often provide preliminary information of great value. A carefully prepared topographic map that the geologist can carry into the field is desirable. This should clearly show all topographic relief and important land subdivisions and reference points that can be correlated with the field studies. It should be drawn to such a scale as will permit of geologic field data being accurately detailed. If an appropriate map is not available, the making of one will be the first care of the geologist on going into the field.

Mapping for Geologic Reconnaissance

Topographic maps are made by instrumental methods familiar to all engineers, establishing, first, a triangulation system of reference points to which a plane table survey can be tied; or the topographic details may

be gathered with transit and level. For rough reconnaissance work, maps of approximate accuracy can be made with the aid of a telescopic hand level equipped with stadia wires, or an Abney level or Brunton compass. Elevations of major reference points are determined with an aneroid barometer. Only such parts of the area as the geologist indicates as of possible structural interest need be detailed. Photographic methods find occasional use in the preparation of topographic maps; it is possible to construct maps of fair accuracy by taking a series of photographs in various directions from carefully chosen points with a camera of special design.

Use of Aerial Photographic Maps in Petroleum Exploration

One of the greatest conveniences in modern petroleum exploration is found in the use of aerial photographs and maps made in the form of a mosaic of matched photographs taken from the air.[5] In making such photographs, a plane carrying a camera is flown in straight courses over the area to be photographed at an elevation of from 1 to 3 miles. The lens of the camera points vertically downward, and exposures are made at brief time intervals so that the photographs overlap. On completion, the resulting photographs are trimmed and fitted together so that they form a continuous strip showing the surface of the earth over which the plane has traveled. If a wide area is to be mapped, the plane is flown in parallel courses over the area, providing sufficient overlap in the exposures so that the photograph strips may be fitted together to form a mosaic of the entire area. To avoid cloud shadows and atmospheric haze, aerial photographs should be made only on clear days, preferably 2 or 3 hr. before or after noon, in order that objects on the surface of the earth will develop some shadow.

Aerial maps have certain definite advantages over ordinary topographic maps. One of the principal advantages is found in the wealth of detail which they afford. The location of every trail, fence line, stream, tree and bush is clearly shown. An area may be mapped much more rapidly by this means than by other methods. As much as 200 square miles may be photographed in a single day, and it has been estimated that 90 per cent of the time ordinarily spent in making topographic surveys can be saved. The cost of maps prepared by this method is consequently lower, ranging from $65 to $100 per square mile. An important advantage from the standpoint of the exploration geologist is found in the ability to produce a satisfactory working map of a tract without disclosing to property owners his interest in the area. Such maps also assist the geologist in many ways in the gathering of information upon which he bases his structural interpretations. Before going into the field he may gain an accurate impression of the drainage and

physiography of the area. The most convenient means of access to various parts of the locality are apparent, and much walking and climbing during the subsequent field survey are avoided. An important advantage in the field use of aerial photographs or photographic maps is the ability of the geologist to locate quickly his position and orient himself with surrounding landmarks. Positions numbered on the photographs can be conveniently correlated with geologic observations in the field notebook. Outcrops are often clearly discernible and can sometimes be traced for considerable distances on an aerial map, though their course may not be clearly apparent to an observer on the ground. From the air one gets a comprehensive view of a large area comprising several or many exposures although on the ground he may be able to see but one at a time. Structural conditions beneath the surface may at times be accurately determined from exposures apparent on an aerial map, and there are cases where anticlines overlooked by geologists in the field using ground-survey methods have been later identified by inspection of aerial photographs. Intersections of fault planes with the surface of the earth are often clearly discernible in the photographs. Abrupt changes in color of the surface soil, or in the character or abundance of vegetation, are ordinarily well displayed on an aerial photograph and may be of significance in the search for oil. Recent advances in color photography and the use of special plate emulsions and filters as applied to aerial photographs have provided a means of recording color differences in surface soils and outcrops and other details that may not be visible to the unaided eye.

In studying aerial photographs an important advantage is gained by observing them through a stereoscope. The stereoscope comprises a system of mirrors and lenses which produces the effect of a third dimension, so that hills, cliffs, trees and other objects on the earth's surface stand out in bold relief. In viewing photographs under the stereoscope, two adjoining and overlapping prints must be properly oriented and spaced apart beneath the mirrors until two images of the same point appear as one. So real is the impression of depth that it is possible to estimate differences in vertical elevation if some horizontal distances on the ground are known. The best stereoscopes for this purpose are intended for office use, but satisfactory folding stereoscopes designed to be carried into the field are also available.

Conduct of Geologic Surveys

Provided with a suitable map, the geologist first enters the field with the purpose of making a broad reconnaissance survey of the entire area to which he is assigned. This will be conducted in such a way as to disclose the more promising areas as early as possible. Early delineation

of the more favorable areas is advantageous in order that they may be designated for detailed study which ordinarily follows the reconnaissance survey. If sufficient personnel is available, however, the detailed survey of the more favorable locations may be proceeding simultaneously with further exploration of the areas not yet classified. In reconnaissance work, accuracy is often subordinated to time; it is frequently necessary for the geologist to work rapidly in order that land options and leases can be secured before the attention of competing interests is drawn to the area. When competition for acreage is keen, time may not permit of a detailed survey of even the more promising areas before an effort is made to acquire the property rights.

With interpretation of geologic structure the primary purpose, attention is directed to the collection of field data that will assist in the determination of dips of flanks and direction and inclination of axial lines of folds. The surface topography is often suggestive of the subsurface structure. Drainage slopes, dip slopes, topographic "highs" and asymmetric ridges are carefully observed by the geologist familiar with physiographic relationships.[2] More exact information relative to subsurface structural conditions is found where the eroded edges of the harder and more resistant strata intersect the surface. Here the dip and strike may be accurately measured, and by taking such measurements at different points along the outcrop of some persistent stratum its disposition beneath the surface may be deduced with considerable accuracy, particularly if a closure on the map is indicated. Where favorable exposures are found, dips are measured with the clinometer, while a Brunton compass may serve to determine the strike. Information so secured is noted directly upon the field map by appropriate symbols. Descriptive notes presenting additional field observations are correlated with the field map by serial numbers. The geologist must always know his exact position on the map in order that observation points may be properly located. Rough triangulation with major reference points, or approximate measurement of distances from property lines and corners, may serve as a means of map location where topographic detail is not adequate. Distances may be determined by pacing, by hand-level stadia observations or by actual tape measurement. The hand level also serves for approximate measurement of relative elevations, and where absolute determination of elevations is necessary the aneroid barometer may be used.[6]

Where the topography is rugged and the formations are steeply dipping, identification of structure is easier than where the area is of low relief and the beds are inclined but a few degrees from the horizontal. In the latter case, resort must be had to careful instrumental methods of survey. It will be important in any case to discriminate between pre-

vailing regional dips and those of local folds superimposed thereon. When the outcrops are obscured by surface alluvium, the position of a stratum must be inferred, though "float" fragments will often fix the position of the stratum between exposures quite definitely. In localities where few well-defined outcrops are to be found, resort may be had to geophysical methods of exploration, described in a later section of this chapter. Faults are an added complexity and their location will often be a matter of considerable importance. Where their line of intersection with the surface can be definitely identified, the direction and amount of displacement will be of special interest. Variation in dips of formations on opposite sides of an unconformity should receive careful consideration. The direction of ancient shore lines, which customarily display a general parallelism with the trend of bodies of sediment laid down along them, will be significant information.

The geologic field party ordinarily consists of the geologist and one, two or three assistants serving as instrument men and rodmen. In exploring remote areas, camp facilities and additional assistance may be necessary. Transportation will be by whatever means the locality affords. In regions where conditions are favorable for their use, the automobile and airplane have greatly facilitated the work of the geologist and permitted him to extend the survey far from his base of operations; but in rugged, inaccessible regions, recourse must be had to pack animals.

In gathering the field data, the geologist should be on the alert for any surface indications of the presence of petroleum that may be in evidence, or for fossil indicators that may serve to determine the geologic age of the formations from which they come. Correlation by this means with like formations bearing a definite relationship with oil deposits in other regions will be valuable evidence. Knowledge of the geologic age of the petroliferous horizons of the region and ability to identify these in the field by paleontological methods are of great assistance. Paleontology finds one of its chief uses in the field of applied science, in petroleum exploration.

A knowledge of the paleontological and generic relationships* of petroleum greatly aids the prospector in roughly classifying areas which are improbable, possible or favorable for the production of petroleum. Unfavorable areas for the production of petroleum include, generally speaking, the more extensive areas of igneous rocks, all pre-Cambrian strata, intensely folded mountainous areas older than the Cretaceous, regionally metamorphosed strata, continental or fresh-water deposits, thick, uniform marine formations devoid of interbedded dark shales, limestones, marls and fossiliferous sandstones. Possible petroliferous areas

* WHITE, D., Genetic Problems Affecting Search for New Oil Regions, *Am. Inst. Min. Met. Eng. Trans.*, vol. 65, pp. 176–198, 1920.

include gently folded Cambrian and Ordovician strata, saline-lake deposits, and highly folded marine strata younger than the Jurassic, especially those of Cenozoic age.* The prospector should give special attention to all marine and brackish water sediments younger than the Ordovician, especially if they are not intensely folded or faulted. Conditions are particularly favorable if the formation is made up of porous, thin-bedded sandstones, limestones and dolomites interbedded with shale and if it appears that the sediments have been deposited in salt water at comparatively shallow depths.

If it seems likely that the results of the field survey will lead to drilling operations, the geologist should select the most promising locations for test wells, with particular reference to structural conditions but also with regard to accessibility, power and water supply and other conditions of practical importance. The results of the geologic field survey are eventually embodied in a report which reviews the work done, comments upon the field observations and presents the geologist's conclusions and recommendations. The latter will deal particularly with the location of proposed drilling operations and acquisition of properties within the prospective area. The report will be accompanied by a copy of the field map, together with structural sections and subsurface contour maps which may have been developed therefrom.

GEOPHYSICAL EXPLORATION INSTRUMENTS AND METHODS

In localities where there are few surface exposures which permit of determining the strike and dip of strata, it is often difficult to form any dependable concept of the subsurface structural conditions. In heavily forested areas, or in valleys where the structural features are obscured by considerable thicknesses of surface alluvium, the geologist following conventional field methods of study may be of little help in locating areas where conditions favorable for accumulation of petroleum exist. In such cases, resort may be had to the use of certain types of geophysical instruments which assist in furnishing information concerning the nature of the subsurface formations. Geophysical data thus assembled may for a geologist skilled in their interpretation provide a means of working out the structural relationships, even though surface signs are lacking or inconclusive. The location of salt domes, faults, buried hills, unconformities and other geologic and structural features may under favorable circumstances often be determined with considerable accuracy by geophysical methods.

Geophysical instruments are designed to measure the magnitude of certain earth forces and lithologic properties that to the trained observer

* Woodruff, E. G., Petroliferous Provinces, *Am. Inst. Min. Met. Eng. Trans.*, vol. 65, pp. 199–216, 1919.

are indicative of the character of rock beneath the surface. They may also provide a basis for estimating the depth below the surface of a stratum having peculiar physical characteristics. Three instruments, the torsion balance, the pendulum and the gravimeter, are available for making accurate measurements of the attraction of gravity, which is a function of the density of the subsurface formations. The seismograph in either of several forms may be used in measuring the elastic properties of the subsurface formations of a locality, high explosives being employed to produce earth vibrations, the magnitude and rate of travel of which are recorded by the instrument. Some sedimentary formations contain magnetic minerals so that they locally influence the direction and intensity of the earth's magnetic field as recorded by a sensitive magnetometer. Earth formations are conductors of electricity in varying degree, and several different instruments are available for measuring earth resistivity or conductivity while others are designed to indicate the magnitude of inductance resulting from flow of electricity through the earth. Radioactivity has been noted in some oil-producing areas, and instruments capable of detecting this property have found limited use. It has also been suggested that instruments designed to measure the ability of an earth stratum to transmit or reflect radio waves may find application, but it has not yet been demonstrated that there is sufficient difference in the extent to which earth formations exhibit this property to provide a practical basis of identification.

The geophysical instruments and methods that have been mentioned in the foregoing paragraph must not be confused with the many different forms of divining rods and "doodle bugs" that have been and still are exploited to some extent by individuals who claim to be able, with the aid of such devices, to locate deposits of petroleum, natural gas and other mineral products of economic value. These devices are supposed to operate either by some supernatural power or influence of the operator, or by some obscure chemical, physical or electrical influence not yet known to science. The informed petroleum technologist will, of course, place no faith in such methods, but an uninformed, credulous public still affords a fertile field for those seeking to exploit their devices and sell their services in the search for oil.

A detailed description of the various geophysical instruments, of the methods used in their operation and in the interpretation of their results, is beyond the scope of the present work. Geophysics is a highly specialized science and is not properly regarded as a part of the field of the petroleum engineer. He should nevertheless be familiar in a broad way with the character of the instruments and methods used and with their possible applications. When geophysical observations and interpretations are to be made, a geophysicist skilled in the use of the instruments and in

making the somewhat complex computations must be employed. It is the author's purpose here to present only such an outline of this related field as the petroleum engineer has need of in the work of oil-field development. This general familiarity with geophysical methods is of value to the engineer not only in connection with the problems of petroleum exploration, but it is expected that geophysical instruments may also find application in various phases of oil-field exploitation. Interesting possibilities are found in the use of special types of geophysical instruments in wells, at depths far below the surface, for purposes of correlation of strata from one well to another, location of edge-water lines, determination of the character of fluid content of strata and other related problems.

Gravimetric Methods

It is well known that there are notable differences in the densities of various types of rocks composing the crust of the earth. Where a stratum of rock differs materially in density from overlying and underlying formations, it is possible, by making observations at the surface with a sensitive instrument designed to measure the attraction of gravity, approximately to estimate variation in depth at various points to its upper surface; or, where a mass of salt or igneous material has been intruded into heavier or lighter sediments, the measured attraction of gravity will locally vary from that normal for the region. As we approach such a locality, there will be a measurable horizontal component of gravity pointing either in the direction of, or away from, the mass of abnormal density, depending upon whether it is heavier or lighter than the surrounding rocks. By taking observations which show variation in the attraction of gravity or the gravitational gradient at many different points within an area, it is possible to map the location of salt domes, buried limestone hills and granite ridges; or, where a limestone bed is faulted so that the portion on one side of the fault plane lies nearer the surface than the portion on the opposite side, it is possible to determine the position of the fault plane with considerable accuracy. Three instruments are available for making gravimetric measurements: the torsion balance,[6] a precision instrument of great sensitivity; the pendulum,[26] less sensitive than the torsion balance but in certain designs sufficiently so for reconnaissance purposes and having the advantage of greater rapidity of operation; and the gravimeter, a device that has largely displaced the torsion balance and pendulum because of the ease and speed with which it may be applied under field conditions.[37]

Seismic Methods

Among the more successful of the geophysical methods thus far used in petroleum exploration are those which are based upon the varying speed with which rocks of different types transmit vibrational waves. Their ability to do this is a function of their elasticity. Rocks possess this property in varying degree, the softer, less thoroughly consolidated rocks and formations transmitting vibrational waves less rapidly than the harder, crystalline and well-consolidated formations. It is also found that the older formations generally display a higher speed of transmission of seismic waves than do the younger rocks. Speeds of transmission of seismic waves range from 90 to 7,000 m. per second. In the practical application of this method vibrational waves are developed by detonation of dynamite at a selected point, while sensitive

seismographs are placed at some distance away in various directions to receive the vibrations transmitted through the intervening rock formations and record their time of transmission. The time of transmission is very brief—only a matter of a few seconds at most, and an accurate and dependable method of conveying the exact time of the explosion to the recording instruments must be provided. This is conveniently accomplished by wireless telephony, an electrical circuit being automatically broken by the explosion. Vibrations of the receiving instrument are recorded mechanically and photographically together with a suitable time scale, by reference to which the interval between the time of the explosion and the arrival of the vibratory waves may be determined. Time intervals of 0.01 sec. can be measured.[27]

Several different vibrational waves may reach the recording instruments, and it is important to be able to distinguish between them. One wave moves through the surface formations at comparatively slow speed. This is of little significance. A second wave is transmitted downward into the deeper formations, which often contain some mass or stratum of more elastic material that transmits the vibrational wave more rapidly. Though the path of travel is longer, this deep-seated wave may arrive first at the recording instrument. This latter wave, which is of particular interest to the geophysicist as an indication of the character of the rocks beneath the surface, has two components, termed "longitudinal" and "transverse." The former, which is the component in the direction of movement, is the faster of the two and is the one commonly observed. In addition, the recording instrument may receive reflected waves from the upper surfaces of more elastic members of the deep-seated formations. The latter are apt to be locally intensified in certain localities, being dependent upon the angle of reflection from the deep-seated reflecting surface. Sound waves traveling through the atmosphere customarily also reach the recording instruments and may be used as a means of timing the explosion if the distance traveled is known or can be estimated. The speed of the air wave, of course, is much less than that of the earth wave.

In use of the seismic method in the search for salt domes in the Gulf Coast region of Texas and Louisiana, where the method has attained its greatest success, reconnaissance surveys have been conducted over wide areas.

In addition to their highly successful use in the location of salt domes, the seismic methods have been used to advantage in locating fault lines, unconformities and buried granite ridges. They may also find use in identification of structural features whenever a high-speed bed occurs in a mass of less elastic strata and in estimating depths to the basement complex through superimposed sedimentary formations.

Use of the Geophone in Gathering Subsurface Data in Wells.—The geophone is an instrument closely related to the electric seismograph previously described, in that it magnifies and may be used to transmit electrically and record vibratory earth waves. With suitable apparatus the vibrations may be heard as sound, or they may be electrically recorded by means of the oscillograph.* This instrument has the advantage that the receiving instrument can be located at a distance from the recording instrument. The receiving instrument, furthermore, is sufficiently compact to be lowered into a well on an electric cable through which the electric impulses are transmitted to the recording instrument at the surface. With this device it is possible, by successively setting off shots at intervals around the arc of a circle about the well on the surface, to estimate the extent to which the well mav deviate from the vertical. Correlation of strata from one well to another, near by, is also possible

* Ilsley, L. C., Freeman, H. B., and Zellers, D. H., Experiments in Underground Communication through Earth Strata, *U. S. Bur. Mines Tech. Paper* 433, 1928.

by this means. Other interesting variations of the usual seismic methods are possible when the receiving instrument may be placed at depth within a high-speed stratum the lithologic character of which can be accurately determined by core samples taken during the process of drilling.

Magnetic Methods

As is well known, the earth's magnetic field varies in intensity and direction from point to point and at the same point at different times, but in the vicinity of formations containing concentrations of magnetic minerals important deviations from normal may be locally observed. A compass needle supported in such a way that it may rotate in a horizontal plane tends to align itself with the magnetic lines of force, the angle between the direction of the needle and the true north being its "declination." At any point the magnetic force acting in the direction of the needle in a horizontal plane is called the "horizontal component" of the earth's magnetic field. If a "dipping needle" capable of rotating in a vertical plane about a horizontal axis is placed with its axis perpendicular to the magnetic lines of force, one end of the needle will dip or point downward into the earth. The angle which the needle makes with a horizontal plane is called the "angle of dip" or "inclination," and the vertical force acting on the needle is called the "vertical component" of the earth's magnetic field.

Magnetometers of several different types are available for exploring the earth's magnetic field, such instruments employing the magnetic needle in one form or another.[24] Some are designed to measure the horizontal component and others the vertical component of the earth's field, but for petroleum exploration purposes one measuring the magnitude of the vertical component is especially useful. The "earth inductor" is another type of instrument that may be used.

Important magnetic anomalies have been noted in the vicinity of many oil fields and in oil-producing regions, but they are apparently not directly connected with the occurrence of oil. They are usually indicative of the proximity of igneous or metamorphic rocks carrying abnormal amounts of magnetite, ilmenite, pyrrhotite and other magnetic minerals. Distribution of these minerals often has structural significance, but interpretation of such occurrences is usually difficult. Magnetic surveys have been helpful in deciphering structural and lithologic conditions in the vicinity of some of the salt domes of the Gulf Coast region of the United States, in exploring for buried granite ridges and magnetic dykes in Kansas, Oklahoma, north and west Texas and Mexico. Magnetic surveys in some California oil-producing areas are reported to have shown isodynamic contours closely paralleling the structure contours.[33]

Electrical Methods

Electrical methods of geophysical exploration have thus far been less used in petroleum exploration than the gravimetric, seismic and magnetic methods, but possess interesting possibilities for future development. In applying the electrical methods we seek to measure the relative conductivity or specific resistivity of the earth formations of a locality. Ability of different types of rocks to conduct electricity and the resistance offered to transmission of electrical impulses vary widely. In addition to varying conductivity exhibited by the rock mass itself, the character of the fluid stored within its pore spaces has an important influence. Dry rocks are poor conductors in comparison with rocks saturated with saline water. Oil within the pores of a rock, on the other hand, offers very high resistance to the flow of current.

The utility of the electrical methods in petroleum exploration has been questioned

by some authorities who find it difficult to correlate structural conditions with electrical observations except under favorable conditions. The absence of any recognizable conducting stratum is sometimes a barrier. Because of the shielding effect of surface formations, it is often difficult to attain any considerable depth penetration. On the other hand, there are cases in which it has been possible by these methods accurately to map buried structures possessing little or no surface expression. An interesting application is found in the use of an electrical method to map structures more than 5 km. offshore, under the bed of the Caspain Sea in the Baku region. One electrical method is said to be effective to depths as great as 6,000 ft. Although under favorable conditions it is apparently possible to correlate structural conditions with observations made by electrical methods, the results secured are often difficult of interpretation.

Measurements of Terrestrial Radioactivity

Studies of radiometric emanations from the earth have shown that slight changes in the radioactivity of various earth formations can be detected by comparatively simple photographic, ionization or calorimetric methods. Radiometric methods were first used in the location of ores containing a high percentage of radioactive substances and for measuring radium emanations in springs producing water used for medicinal purposes. Application of these methods in searching for oil is based on the supposition that since petroleum is an organic compound it has the power of absorbing radioactivity from surrounding formations and that indications of radioactivity at the earth's surface would therefore be more intense in the vicinity of oil deposits. Experiments conducted in the Maikovsky district of Russia by the radiometric subsection of the Institute of Practical Geophysics* have shown marked increase in radioactivity in the vicinity of the oil deposits. Other investigators have expressed the opinion that radioactivity observable in certain areas is the result of emanations from radioactive minerals that bear no relation to the presence of oil. Insofar as is known to the author, this method of geophysical exploration has not been used in petroleum exploration in other than the region mentioned so that it is not yet known whether it is of general or merely local application. It is of interest, however, as the only one of the geophysical methods which responds directly to the presence of oil.

Geochemical Exploration Methods

As a result of field and laboratory studies of samples of surface soils gathered in areas overlying and immediately surrounding oil and gas pools, it has been established that such soils often contain small amounts of natural gas or even liquid hydrocarbons which have apparently found their way through the intervening rock masses by leakage through the cap rocks. By oxidation of certain gaseous or liquid hydrocarbons, paraffin waxes may be formed in surface soils. This discovery has been responsible for a practice of field exploration known as "soil analysis" that has been widely applied during recent years in the search for new oil and gas fields.[34] In this, samples of soil are gathered at intervals over the area to be examined in accordance with a definite grid or profile, preferably at a depth of several feet below the surface. An augur hand drill is used for this purpose. The samples are then placed in airtight containers and removed to a laboratory where they are subjected to extraction and delicate tests to determine their hydrocarbon content. Pirson postulates a dynamic rather than a static condition of the hydrocarbons in the surface soils and suggests a method of gathering "soil-air" samples by application of vacuum.[38]

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* Lee, F. W., Russian Papers on Measurements of Terrestrial Radioactivity, *U. S. Bur. Mines Circ.* 6072, 1928.

In the laboratory, the analysis is conducted by driving the occluded or adsorbed gases from the soil samples by application of heat, and after removal of water, methane, ethane and other hydrocarbon constituents are separated by fractional distillation and determined quantitatively by ignition. A more recent technic involves the use of the mass spectrometer as a means of identifying and quantitatively measuring the hydrocarbon constituents of gases evolved from soil samples.[25]

The hydrocarbon values thus determined are plotted on a map at the sample points and the pattern of relative amounts of hydrocarbons is indicated by contouring. On inspection of the resulting map, it is often found that the higher hydrocarbon values are grouped around the productive area in a characteristic "halo," not only indicating the presence of an oil accumulation below but also suggesting its areal expanse. The methods of geochemical exploration may also be applied as a process of well logging by chemical analysis of drill cuttings obtained in the course of drilling (see page 648).

It has also been noted that the ash obtained by burning various plants contains elements obtained from the soil in which the plants have grown. Chemical analysis of the ash will sometimes disclose concentrations of certain elements that occur to a lesser degree in the surface soils, and there has been some indication that these elements are indicative of the presence of hydrocarbons in the soils.

DRILLING FOR SUBSURFACE INFORMATION IN PETROLEUM EXPLORATION

At times, neither geologic nor geophysical reconnaissance furnishes sufficient information to enable the geologist to form a reasonably accurate conception of the subsurface structural conditions; yet, the locality may be of sufficient promise to justify the belief that, if a suitable structure exists, petroleum may be found. In such a case it may be justifiable to expend money in the drilling of one or more wells for subsurface information. In regions where the productive horizons occur in formations unconformable with the overlying beds, the structural relationships below the unconformity may be impossible to decipher without the information that may be furnished by one or more wells drilled from the surface to intersect the lower formations. A single well may furnish cores of the formation penetrated, which provide an accurate record of the lithologic characteristics of the component strata, and if the well is vertical and the cores can be properly oriented the approximate dip of the formations can be determined (see page 694). The logs of two wells permit of some degree of correlation from which approximate calculations of the inclination of strata between the two locations may be made. Three or more wells provide information for a complete and accurate determination of the dip and strike of any continuous stratum that can be definitely identified in each.

Drilling for structural information is often conducted with the aid of the diamond drill (see page 345), which affords excellent cores and, when light portable outfits are used, is more rapid and less expensive than drilling by churn or rotary methods. However, portable and semi-portable rigs of both churn and rotary type are also occasionally used for

this purpose. Wells drilled for structural information are often but a few hundred feet deep, though there are many instances in which deep wells have been drilled, primarily with the purpose of securing subsurface geological data. Such wells are often smaller in diameter than those drilled for production purposes, frequently only 2 to 5 in. In the event that a productive oil sand is encountered and it is desired to produce through them, they may be reamed to a larger diameter at small cost. However, if the well is to be of considerable depth and it is thought that there is a fair chance of securing commercial production, it will generally be preferable to drill a full-sized hole by the usual cable-tool or rotary methods. In the event that production is secured, it is difficult to make a fair test of the productive capacity of an oil-bearing stratum in a well of less than normal diameter.

LOCATING TEST WELLS

After the subsurface structural relationships have been deciphered and a decision has been reached that conditions seem sufficiently favorable to justify the drilling of a test well, it will next be the task of the exploration geologist to select the most promising position for the well. In locating test wells the geologist will be primarily influenced by structural conditions, but, insofar as it is consistent with this, he will also be influenced in making his selections by considerations of accessibility and property ownership. It will, of course, be essential that title be secured to the property upon which the test well is to be drilled or, at least, the right to drill and produce and remove oil and gas therefrom. In will also be desirable that the exploration interests secure title to a sufficient surrounding acreage to guarantee a reasonable profit on their activities in the event that the test well proves to be commercially productive.

Structure being the primary consideration, the geologist will strive so to locate the test well as to secure the maximum advantages that structure affords. In locating test wells on dome and anticlinal structure, the prospector should aim to penetrate the petroliferous stratum at its structural crest. Here nature's forces are concentrated—the gas pressure is greatest, and the possibilities of high and long-continued production are at their best. A well drilled in any other location, if unproductive, would still leave the presence or absence of oil in the formation in doubt. An unproductive well on the structural crest settles the issue at once unless there is reason for believing that the sands are lenticular or are influenced by irregular cementation. The only exception to this general rule of locating the test well to intersect the supposed oil-bearing stratum at its structural crest is found where abnormally large gas concentrations under high pressure are expected, owing to unusually favorable structural conditions. In such cases, a well directly on the crest of the structure

might produce only high-pressure gas for a considerable period before oil could force its way up from lower levels into the well. A well located slightly down-dip from the structural crest might in such a case produce oil at once and could be operated under more favorable conditions.

It is well to remember in selecting sites for test wells on asymmetric anticlines that the productive limits of the pool will probably extend farther from the axis in the direction of the flat-dipping flank than on the side of the steeply inclined flank (see Fig. 2). Consequently, if there is doubt concerning the precise location of the axis, preference should be given to the flat-dipping side in locating the initial well.

In determining the location of axes of asymmetric folds at depth from surface measurements, it should be noted that the axis of a stratum several thousand feet deep may be in quite a different position from the axes of the surface strata, though they are parts of the same fold. This is demonstrated in Fig. 2, in which it may be observed that the axes of the deeper strata fall successively to the right of the axes of the overlying strata. A careful structural study based on accurate field data is essential before a test well can be properly located to penetrate the oil stratum at its structural crest.

In locating test wells on monoclinal structure, the wells must be located sufficiently down-dip to penetrate the oil stratum below the zone of surface influence, which may extend for several hundred feet below the outcrop. Oils produced from the upper portion of the stratum, near the outcrop, are likely to be heavy and viscous, and the wells will be small producers because of the difficulty of inducing flow from the sands and because of the absence of gas. Except for this limitation, considerations influencing location of wells on monoclinal structure are identical with those discussed in connection with anticlines and domes. If the dip of the outcropping strata is measurable, it is a simple matter to calculate from the observed angle the proper distance of the well from the outcrop, to intersect the oil zone at any desired depth.

The location of test wells with respect to other types of structures than those discussed in the foregoing paragraphs presents a somewhat more complex problem, and one upon which it is difficult to generalize. Where faults enter as a factor in determining the structural relationships, one should remember that the possible oil accumulations are always on the side of the fault plane in the direction of the downward-dipping formations. If, however, this happens to be on the "footwall" or underside of the fault plane, it may be necessary to drill through the fault plane and hence to locate the wells at the surface on the side opposite to that on which the accumulation is conceived to occur (see Fig. 11). Abrupt changes in the strike of the fault plane may be particularly significant. A still more uncertain situation is presented in locating test wells on salt

domes. Oil may not be present at all or, if it is, it may be in the sediments on one side of the dome but not on the others, or there may be an accumulation on top. Several or perhaps many test wells may be necessary before a salt dome can be abandoned as nonproductive. Where an unconformity intervenes between the surface exposures and the formations in which production is sought, or where there is reason to believe that the oil-reservoir rock is highly lenticular, most uncertain conditions are presented and much more or less "blind" drilling may be necessary to test adequately the productive possibilities of an area.

SUBSURFACE INDICATIONS OF PETROLEUM THAT MAY BE OBSERVED IN THE DRILLING OF A WELL

During the drilling of a test well there are occurrences that may be significant in indicating the proximity or presence of petroleum. Knowledge and observation of these will enable the geologist to advise those in charge of drilling operations concerning the prospects for further drilling. Even when the surface signs are unmistakable, the evidence to be obtained from the log of the well during the drilling stage will be of great value in checking previous estimates and also in the subsequent development of the field through the drilling of additional wells.

Oil-saturated sand or even traces of oil in the pulverized material bailed or pumped from the well are, of course, direct evidence and usually justify a production test of the stratum from which they come. Such a test is often necessary to determine whether or not oil can be produced in sufficient quantity to repay the cost of operation. The driller will always be on the alert for "shows" of oil when the drill enters a soft, porous sandstone after penetrating a hard layer of close-grained "shell." It will often happen that the finely pulverized material pumped or bailed from the well will be so thoroughly washed that its petroliferous character is not evident until tests are made. An ether, chloroform or acetone test will usually determine whether or not oil is present.

Flows of hydrocarbon gases from a drilling well are always favorable evidence, especially if they contain gasoline vapors or if they have a petroleum odor. Many sedimentary formations produce marsh gas (methane) which, if dry (*i.e.*, without hydrocarbons of higher molecular weight), is often formed in the absence of petroleum, and therefore it is not necessarily indicative of the presence of oil.

Traces of solid or semisolid hydrocarbons, such as mineral wax, asphalt, fossil resin, tar or even coal or lignite, in the returns from a well constitute favorable indications of the presence of oil.

Waters and gases containing hydrogen sulphide or sulphur dioxide are generally favorable indications unless the water is hot. Hot sulphur waters are characteristic of regions under the influence of volcanic and

solfataric activity, conditions generally unfavorable for the accumulation of petroleum.

The presence of igneous or highly metamorphosed rocks is necessarily regarded as unfavorable for the discovery of petroleum in the formations beneath. Brine is generally looked upon as an unfavorable indication when encountered in a prospect well. Though it is nearly always associated with petroleum, it generally underlies the oil; consequently, if a well produces brine, it is often inferred that the zone in which oil might be found has been penetrated and found barren.

Aside from the more direct indications of petroleum suggested above, it should be pointed out that mere alternation of stratified porous and impervious beds in horizons known to be petroliferous is in itself a favorable indication. Great thicknesses of either coarse or close-grained rocks, without variety in porosity and texture, never offer favorable conditions for the accumulation of petroleum.

Dissolved Salts Present in Ground Waters Sometimes Significant

In some fields it is found that the percentage of certain dissolved salts in the ground waters increases or decreases in a characteristic manner. In such cases it is possible to form some estimate of the proximity of an oil sand from a chemical analysis of the waters contained within the various strata penetrated by the well. Waters a short distance above the oil horizon in many fields are "sulphur waters," containing considerable percentages of hydrogen sulphide; but the shallow surface waters and those within the oil measures generally contain no sulphides. Carbonates, which are present only in moderate amounts in the shallow waters, increase in percentage as the oil zone is approached. If no chlorides are present, the carbonates may constitute the only dissolved salts in the waters immediately associated with the oil. As pointed out in the preceding paragraph, however, the waters underlying petroleum, occupying the lower horizons of the same strata in which the oil occurs (*i.e.*, "edge waters"), are often rich in chlorides. Although the surface and shallow ground waters contain considerable percentages of dissolved sulphates, these are found to diminish as the oil measures are approached and finally entirely disappear. Outside of localities in which petroleum occurs, on the other hand, sulphates are found in even the deepest waters.

Geothermal Gradients

Measurements in wells of the rate of temperature increase with depth have shown that in many oil fields the rate of increase is greater than is normal in sedimentary formations in the same region. Various theories have been offered to account for this. Some authorities have suggested that it is possibly due to some obscure chemical reaction in which petroleum plays a part, but information recently obtained in

several different petroleum-producing regions indicates that petroleum itself probably is in no way responsible. In a number of oil fields where detailed studies have been made of the geothermal gradient, it has been found that variation in the gradient bears a direct relation to structure, showing the most rapid rate of increase at the structural crest. Some observers believe that circulating ground waters are responsible for variations in the gradient that have been observed. In other instances it appears that proximity to igneous or metamorphic rocks may be the explanation of an unusually rapid rate of increase in ground temperature with depth. It has also been suggested that local radium emanations may be active in influencing ground temperatures, but there is little or no evidence to substantiate this view. The present data are too uncertain in character to justify any definite correlation between ground temperatures and proximity to oil-bearing strata, but the information so far collected would appear to substantiate the general statement that ground temperatures higher than normal prevail in petroliferous formations. In this connection, however, the fact should not be lost sight of that high ground temperatures are also characteristic of regions where vulcanism is active and that, without more direct evidence of the presence of petroleum, ground temperatures are of doubtful significance.

Geologic Reconnaissance Not an Infallible Guide

Equipped with a knowledge of the characteristics of petroleum, with its manner of formation and accumulation, its associations and occurrence in nature, the prospector must apply this knowledge in the field in the location of new deposits. The nature of the work requires a happy combination of technical and practical ability, a power to reason and deduce facts which must often be based on very slender and uncertain evidence. Geology is not an exact science. Good judgment and practical experience in field methods are of far greater value than mere academic understanding. Usually it will not be possible for the geologist to predict with certainty that petroleum will be found in commercial quantities in a given location. Perhaps the best information to be expected from him will be a statement that conditions are either favorable or unfavorable; and if favorable, the best position within the prospective area for the location of a test well should be selected by him. The possibility that a well thus located by scientific methods may prove unproductive is one of the inherent risks in petroleum exploration that must be recognized by all parties concerned in the enterprise.

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CHAPTER III

PRINCIPLES OF OIL-FIELD DEVELOPMENT

ACQUISITION OF LAND TITLES

Before any development work is begun in an area selected for a test well, the prospector should acquire title to the land to be tested or, at any rate, conclude an agreement with the landowner that will protect him in his right to enter upon the land, to conduct drilling operations and to produce and sell any oil or gas that may be discovered. In the United States, if the proposed site of the well is on the public domain, the exclusive privilege of testing and leasing may be secured under the provisions of the Mineral Land Leasing Law of 1920. If the land on which drilling is to be conducted is privately owned, title may be secured by purchase in fee or, more commonly, by completing a leasing agreement with the landowner. The lease usually grants oil and gas rights only and does not convey title to the land surface, other than the right of entry and use of such part of the surface as may be necessary in exploitation of the property. In return for this privilege, the lease provides that the lessor shall receive a specified percentage of the value of the oil and gas produced and, perhaps also, a cash bonus and an annual rental during such time as the property may be nonproductive.*

The prospector will find it advantageous to secure title not only to the tract on which the well is to be drilled but also to surrounding areas in the trend of prospective development to assure control of a sufficient acreage to repay him for the financial hazards of drilling in the event that commercial production is found. It is to the advantage of the prospector to secure his land titles before his purpose in the locality is generally known, for the mere knowledge that someone thinks highly enough of the prospective merits of the locality to drill a well is often sufficient to inflate values. In many cases, the landowner will grant a lease merely on the stipulation that he shall receive a one-eighth royalty and without payment of any initial bonus by the lessee. Rentals may be nominal or small, perhaps 25 cts. to $1 per acre per year. Such a plan is very favorable to the landowner, for he loses little or nothing if the test fails, and yet he is assured of a substantial part of the profit

* A companion volume now in preparation, entitled "Petroleum Production Economics," will discuss in detail the subject of land acquisition and control in the petroleum-producing industry.

if it is successful. If the presence of oil in the locality is known or suspected by the landowner, a leasing agreement is sometimes the only feasible plan because of the owner's desire to share in any oil that may be discovered.

EXPLORATION: DETERMINING THE PRODUCTIVE LIMITS OF THE FIELD

Once the existence of an oil field has been proved by the drilling of a commercially productive well, interest at once centers on the problem of determining the extent of the field, that is, the area within which production will be obtained and the position of the more productive sections. Knowing that a given area will be productive, the property owner within that area is then confronted with the problem of planning a development campaign with respect to definite boundary lines, which will adequately protect his property against the activity of neighboring operators and which will result in the maximum profit being obtained from the land. The planning of the development program involves careful consideration of a number of interrelated factors, among which are the spacing and arrangement of wells and the economic rate of development as influenced by the cost of drilling, the probable future selling price of oil, the capital cost of the land and its equipment, the productivity and rate of decline of the wells and the interest rate to be demanded on the investment.

The discovery well proves that oil is present in commercial amounts and gives important information concerning the sequence and nature of strata penetrated and the horizon in which the oil is found. The possibility of obtaining production from areas about the initial well will be a matter of conjecture until additional wells can be drilled, though if it is possible to work out the geologic structure from surface evidence and determine the direction of the major axis of the fold in which the oil has accumulated, the geologist may predict the most favorable direction from the discovery well for further development. The type of structure, the magnitude and extent of the fold and the dip of its flanks and axial line will be important considerations in determining the position of second, third and later test wells and the distance at which they may be spaced from the discovery well. Usually the operator will be anxious to "prove" the largest possible area with the fewest number of wells, yet without running the risk of locating a well beyond the limits of the pool and drilling a "dry hole."

If the structure indicates a well-developed anticline or dome, exploration for the limits of the productive area may be conducted by drilling wells first in both directions along the major axis of the structure, locating the wells as nearly as possible along the structural crest, and second along a line at right angles to the axis, locating wells alternately on either side of the crest, thus exploring down the flanks until edge water is

encountered or until the wells become such small producers that they cease to be profitable. If the logs of these wells are carefully preserved, it should be possible, from a study of the results recorded, to gain a fair impression of the disposition of the producing oil sand or zone and perhaps even to draw a rough structure contour map of its top surface. Later drilling along other lines at right angles to the major axis may disclose local variations in dip and thickness of the oil-bearing strata, but such changes will not greatly alter the extent of the productive area as determined from the data accumulated and applied as described.

If the structure is monoclinal, it will usually be possible to locate the outcrop of the productive strata and, by measuring their dip at various points, to determine very closely the depth to production at any location. Usually the first test wells will be drilled near the outcrop so that the wells are shallow, and yet they should be located far enough down-dip to avoid the zone of surface influence near the outcrop. Oils near the outcrop are often heavy and viscous by reason of seepage and evaporation losses of the lighter constituents at the surface and do not give a fair test of the capabilities of the structure. Exploration will be conducted along lines at right angles to the strike, locating wells to penetrate the producing zone at successively greater depths until the lower limits of the pool are encountered.

Factors Influencing Productivity and Form of the Field

From the foregoing it will be observed that location of wells in the development of an oil field is based primarily upon geologic considerations. Although extensions of the field from a discovery well may be predicted on the evidence of structure, the form of the field and productivity of different portions of it will be largely influenced by minor changes in dip or hade of the structure and by lithological variations in the productive strata.

The Influence of Dip and Hade of Structure.—An anticlinal structure with steeply dipping flanks would indicate a narrow productive area—perhaps a long narrow strip of territory along the structural crest. Plunging of the axis at either end of an anticlinal structure would definitely limit the productive area in the direction of the strike. The extent of a field located on dome structure would be greatest in the direction of the lowest dips and relatively narrow in the direction of steep dips. A symmetrical dome with strata dipping at the same angle in all directions is rare in nature. The major structure is often influenced by intersection with minor folds. Two intersecting anticlines may result in forking of the productive area or a local widening of the field. Wells located at such intersections also are likely to be more productive than elsewhere since anticlinal intersections cause doming, with resultant concentration from all directions instead of two. A change in the direction of strike of an anticlinal fold is regarded as favorable to local concentration and high productivity of wells, since here also the lines of oil migration up the dip are brought to a focus, particularly on the convex side of the fold. Though local variations of this character are of importance

in selecting the more valuable areas within a field, it should be recognized that the extent and continuity of the field as a whole are dependent on persistence of structure and maintenance of an approximately level axis.

The Influence of Lithological and Stratigraphical Variation.—The shape of the field and the productivity of areas within it will be greatly influenced by changes in the porosity and thickness of the oil-bearing strata. Variation in porosity, if extreme, will result in highly productive lenticular pools surrounded by almost barren areas, though the major concentration may have been effected by a well-defined anticlinal structure embracing both the productive and nonproductive areas. The more porous and permeable rocks will give higher initial yields, and wells drilled into thick oil sands will be more productive than those deriving their oil from thinner strata. Variation in the thickness of an oil-producing stratum will thus cause great irregularity in property values. Local "pinching out" of a productive sand may result in an area within the heart of a producing field being practically barren.

The extent of the field and the productivity of different portions will also be influenced by the number of oil-bearing strata occurring beneath it. It often happens that there will be several well-defined oil sands, separated from each other perhaps by several hundred feet or more. In such cases the lower strata are often less influenced by the structure, that is, their flanks dip at lower angles and the productive area will be wider. Productive lower zone wells may thus penetrate the upper zone beyond its productive limits. Then too, if the fold is asymmetric, the axis of a lower sand will not conform with that of an upper sand, so that the more productive first-zone wells may be less advantageously located with respect to the lower zone (see Fig. 2).

Correlation of Well Log Data.—Even though competent geologic advice is to be had, the early period of development in a new field will often be one of great uncertainty. Perhaps a number of operators will be in competition with each other for early production and efforts are chiefly directed toward speed in drilling instead of to the important work of securing accurate well log data to aid in correlating and interpreting structural conditions. Many operators consider their well logs as confidential information, so that it becomes a difficult matter for one interested in working out the structural and stratigraphic relationships to secure the necessary data. It is to the mutual advantage of all operators in the field that all available subsurface information be freely exchanged in order that the structural and stratigraphic features may be worked out at the earliest possible time.

Operators in a new field should make an effort to reach a common understanding on the names and characteristics of the more important strata penetrated by the wells so that there will be some degree of uniformity in the well log data accumulated. If there are any persistent strata of striking characteristics that might serve as marker horizons for correlation and reference, these should receive particular attention.

If the well log data are accurate, a peg model* will display the general trend of the structure as soon as a few wells have been completed, and, as

* For a description of the methods of constructing peg models, see Chap. XVI.

more pegs are added, the local dips and irregularities will become apparent. Often local irregularities in depth to production, or dry holes drilled in locations thought to be productive, will cause confusion during the early period of development, and if there are several oil sands within a productive zone, as is often the case, variations in the productive area covered by the different sands may further complicate the problem. Often the position of "water sands" will be uncertain, and irregularities in the position of "water shut-offs" and landing depths for casings in near-by wells will allow water to enter the oil sands at certain points to the detriment of oil production. Obviously, accurate well logs should be the primary consideration during the early period of development, in order that these irregularities may be fully understood and a uniform system of casing wells and excluding water determined upon.

If the ordinary rock characteristics are not sufficiently distinctive to furnish a means of correlating strata from well to well, a closer study of formation samples from a few wells that have been carefully drilled and systematically sampled will usually disclose certain peculiarities that characterize one or more of the persistent strata. A particular sand may contain an unusual percentage of some distinctively colored or crystallized mineral, such as hornblende or biotite or olivine, or the sand grains may be unusually coarse- or fine- or even-textured. Another may contain a particular type of foraminifera or other fossil indicator. The water contained within a water sand may have unusual chemical properties. Often, if there is more than one oil sand, the oil will differ somewhat in gravity in the different strata. Some of these are properties that will require skilled technical assistance in identification, but if such a relationship is once established it will serve as a useful means of correlation, perhaps throughout the entire field. Local irregularities or erroneous log data may by such means be readily adjusted to the established markers and stratigraphical correlation completely established.

PLANNING THE DEVELOPMENT PROGRAM

Unfortunately, the average operator is seldom in control of the entire area within a producing structure. Ordinarily several, or perhaps many, independent operators will own different portions of the field and will enter into competition with each other for production. All produce from what is, in effect, a common reservoir, and the activities of one operator will directly influence the ultimate recovery to be effected from neighboring properties. Location of the early wells in undeveloped territory will therefore be influenced by property lines as well as by geologic structure and local lithological variations; indeed, protection of property lines is often given the greater consideration.

Influence of Neighboring Activity on the Development Program

With the idea of preventing drainage across property lines, it is customary to drill the "outside locations" along boundaries, before the interior locations are drilled. Often the first wells on a property will be placed in the corner locations, thus protecting against drainage by corner wells in the three adjoining properties. The side boundary wells will next receive attention, no interior locations being drilled until all the line wells have been completed.

This program assumes that all surrounding operators are equally active. If all neighboring activity is concentrated on one side of a lease, the boundary wells on that side will be drilled first and perhaps one or two rows of interior wells will also be drilled on that side of the property before attention is given to the other wells along boundaries where competition is not keen. If a property is located on the edge of a producing field, it may be that production on the side nearest the field will be practically certain, while the possibility of obtaining oil in wells drilled along the far side (usually the down-dip side) will be more or less problematical. In such a case, in order to avoid the loss occasioned by the drilling of dry holes, development may proceed progressively down-dip from the boundary nearest neighboring producing wells, drilling of the down-dip boundary locations being deferred until it is fairly certain that they will be profitable producers.

The planning of a development campaign with respect to neighboring activities has both defensive and offensive aspects. The operator who first brings his property to full development will secure more of his neighbors' oil than they are able to secure of his. Closely spaced wells and wells of large diameter will drain an area more rapidly and thoroughly than a fewer number of small wells. Then, too, the early wells in an undeveloped area will usually have the greater ultimate productions. Initial productions are higher because of greater gas pressure during the early stages of development, and the earlier wells seem to maintain their superiority in later years, possibly by establishing drainage channels during the early period before interference by later drilled wells becomes a factor of importance.

Offsetting and Line Agreements

As a measure of protection against drainage across property lines, it has become customary for adjoining property owners to place their line wells directly opposite each other (*i.e.*, on a line at right angles to the boundary line) and at an equal distance from the boundary line, a practice known as "offsetting." If operator *A* drills eight wells spaced 660 ft. apart and 100 ft. back from the line along his west boundary, operator *B*,

owning land on this side, must drill as many wells similarly spaced along his east boundary; otherwise *A* gains the advantage in production from the line wells. This advantage can actually be translated into terms of equivalent acreage. The obvious disadvantage to all parties concerned, of adjoining operators entering into "boundary warfare" through competition in the drilling of line wells, has led in many instances to formal

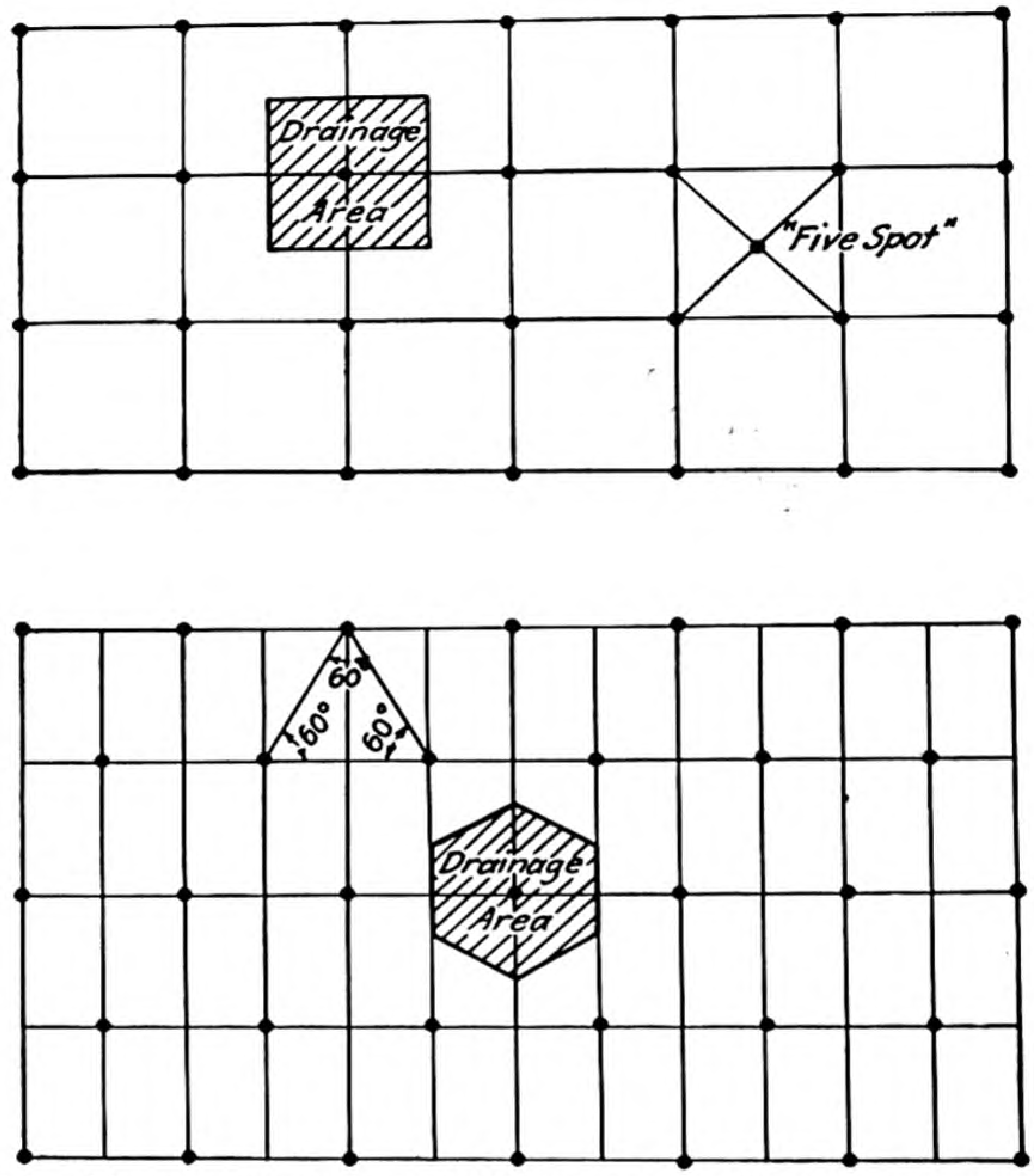


FIG. 15.—Above: rectangular and below: triangular arrangement of wells.

agreement to drill no more than a stated number of wells along the common boundary and to drill not closer than a specified distance from it. Such regulations are sometimes tacitly accepted by all the operators of a field or district, so that the spacing of wells along boundaries is approximately uniform throughout the field. For example, in the California fields, wells are often placed either 100 or 150 ft. back from the line. Spacing along the line will vary in different localities with the prevailing opinion concerning the number of wells necessary to drain the land effectively within a reasonable space of time. Although defensive considerations would dictate the drilling of offset wells along boundary lines directly opposite each other, less interference results when

locations on opposite sides of the line are staggered. This, too, may be accomplished by mutual agreement.

ARRANGEMENT OF WELLS

Some geometric arrangement is usually followed in the placing of wells, locating them in rows across the property and spacing them at some uniform distance so that all portions of the reservoir rock will be equitably drained. A rectangular arrangement of wells is often adopted, but a triangular pattern in which the wells in adjacent rows are staggered gives more complete drainage (see Fig. 15). If it be assumed that oil moves through the reservoir rock toward the nearest well, it is apparent that rectangular spacing provides drainage squares in which the wells are situated at the intersection of diagonals connecting the corners. The acreage tributary to a well in this case is determined by the equation: $a = D^2/43{,}560$. Here D is the distance between wells and a is the number of tributary acres. With the triangular or staggered arrangement of wells, the drainage areas are hexagonal in form. Here

$$a = \frac{0.866D^2}{43{,}560}$$

TABLE VI.—ACREAGE PER WELL AND EFFECTIVE RADIUS FOR DIFFERENT WELL SPACINGS, RECTANGULAR AND TRIANGULAR PATTERNS*

Distance between wells, ft.	Acres per well		Effective radius, ft.	
	Rectangular pattern	Triangular pattern	Rectangular pattern	Triangular pattern
300	2.07	1.79	191	179
400	3.67	3.18	255	238
500	5.74	4.97	319	298
600	8.26	7.16	382	357
660	10.00	8.66	420	393
700	11.2	9.74	446	417
800	14.7	12.7	510	476
900	18.6	16.1	573	536
1,000	23.0	19.9	637	595
1,100	27.8	24.1	701	655
1,200	33.1	28.6	764	714
1,300	38.8	33.6	828	774
1,320	40.0	34.6	841	785
1,400	45.0	39.0	892	833
1,500	51.7	44.8	956	893
1,600	58.8	50.9	1,019	952
1,700	66.3	57.4	1,083	1,012
1,800	74.4	64.4	1,147	1,071

* After Park J. Jones.

It is apparent that drainage squares or hexagons require that some of the fluid from the corners of the areas must travel farther to reach the well than fluid from the nearest points on the sides. For some purposes, it is convenient to think of these drainage polygons in terms of circular areas of equivalent acreage having an effective "drainage radius." Thus, for rectangular spacing, it may be shown that the effective drainage

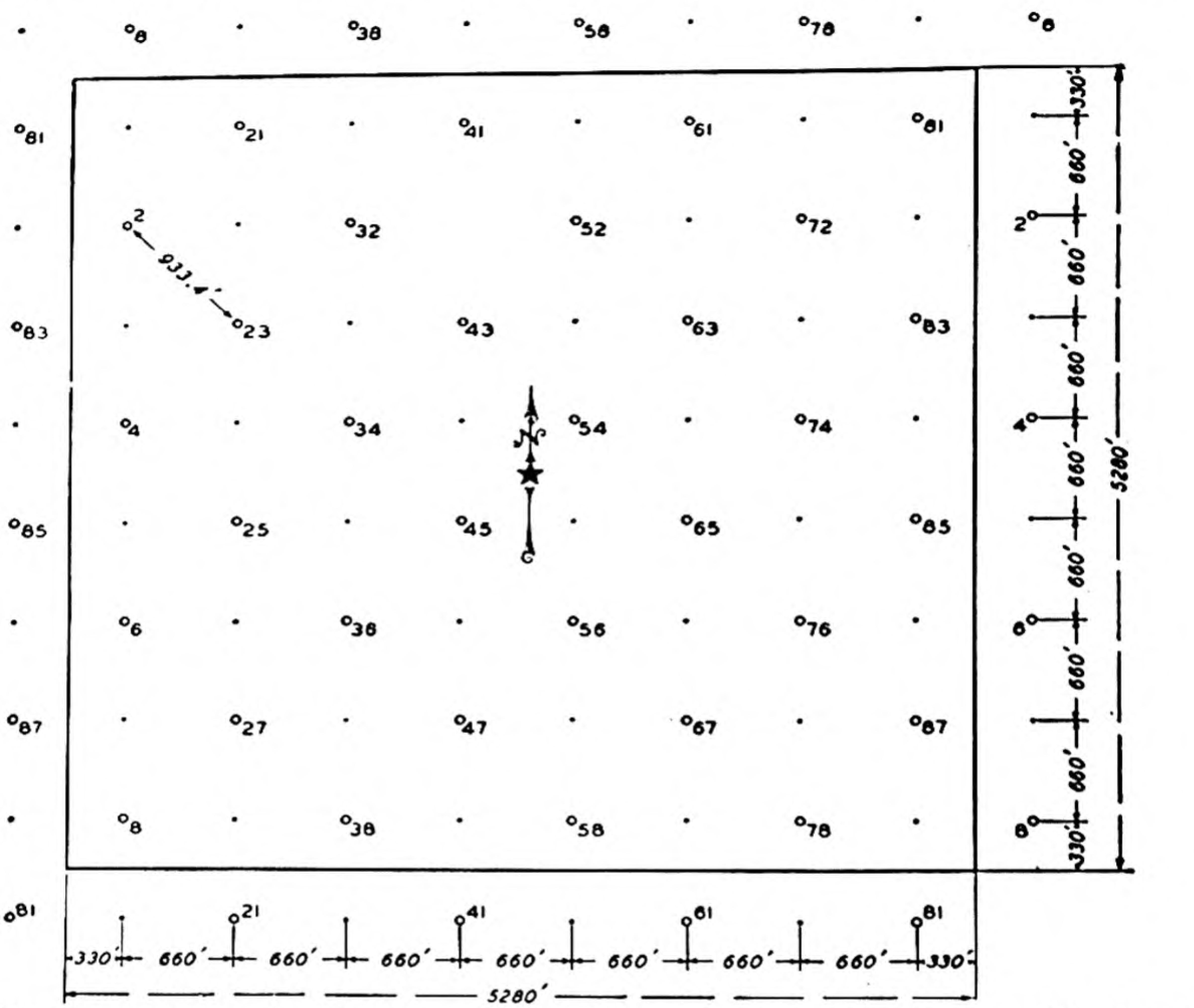


Fig. 16.—Arrangement of wells providing 20-acre spacing, adopted for exploitation of Kettleman Hills North Dome Field, California. Intermediate unnumbered locations, if drilled later, would provide rectangular 10-acre spacing.

radius $R = 0.637D$. For triangular spacing, $R = 0.595D$. Table VI indicates the acreage per well and effective radius for different well spacings within the range used in field practice. An arrangement of wells providing an average of 20 acres per well is illustrated in Fig. 16.

Often the spacing and arrangement of boundary wells will determine the position of interior wells, particularly if the property is a small one. There is better opportunity for scientific well spacing and arrangement when land is held in large tracts than when small acreages are the rule. Town-lot drilling in some Western American fields, with resultant over-crowding of wells and unequal spacing, has resulted in great economic

waste and, in many cases, owing to overdrilling and mutual interference, operations have been unprofitable.

It is customary to number the wells on each property, for convenience in reference, in the order in which they are drilled (see Fig. 17). An

1	7	9	12	14	15	16	3
5	29	31	35	36	37	38	20
6	30	32	39	41	43	45	21
8	33	34	40	42	44	46	22
10	47	61	62	58	57	50	26
11	48	63	64	59	60	51	27
13	49	54	55	56	53	52	28
2	17	18	19	23	24	25	4

Wells numbered in sequence as completed irrespective of location.

1	28	27	26	25	24	23	22
2	29	48	47	46	45	44	21
3	30	49	60	59	58	43	20
4	31	50	61	64	57	42	19
5	32	51	62	63	56	41	18
6	33	52	53	54	55	40	17
7	34	35	36	37	38	39	16
8	9	10	11	12	13	14	15

Helical system. Locations numbered in order irrespective of sequence of drilling.

1	12	13	14	15	16	17	18
2	22	23	24	25	26	27	28
3	32	33	34	35	36	37	38
4	42	43	44	45	46	47	48
5	52	53	54	55	56	57	58
6	62	63	64	65	66	67	68
7	72	73	74	75	76	77	78
8	82	83	84	85	86	87	88

Coördinate system. Locations numbered in order irrespective of sequence of drilling.

1	1A	1B	1C	1D	1E	1F	1G
2	2A	2B	2C	2D	2E	2F	2G
3	3A	3B	3C	3D	3E	3F	3G
4	4A	4B	4C	4D	4E	4F	4G
5	5A	5B	5C	5D	5E	5F	5G
6	6A	6B	6C	6D	6E	6F	6G
7	7A	7B	7C	7D	7E	7F	7G
8	8A	8B	8C	8D	8E	8F	8G

Coördinate system using figures and letters.

FIG. 17.—Systems of numbering oil wells.

alternative plan, one followed by some of the larger oil companies operating many different properties, is to number the wells with reference to their position and irrespective of the order of drilling. One becoming familiar with such a system knows at once, from the well number, its position on the property, but the well numbers would not indicate their relative ages.

RATE AND ORDER OF DRILLING

It is apparent that if we hurriedly bring an oil property to full development, we shall have a rapidly increasing daily production which reaches

a peak rather early in the life of the property and then gradually declines as the productivity of the wells decreases, until, during the later years of the productive life of the property, the daily production reaches a comparatively low figure (see upper graphs, Fig. 18). This plan of development probably results in the greatest ultimate production, but it has the disadvantage that the drilling, production, storage and transportation

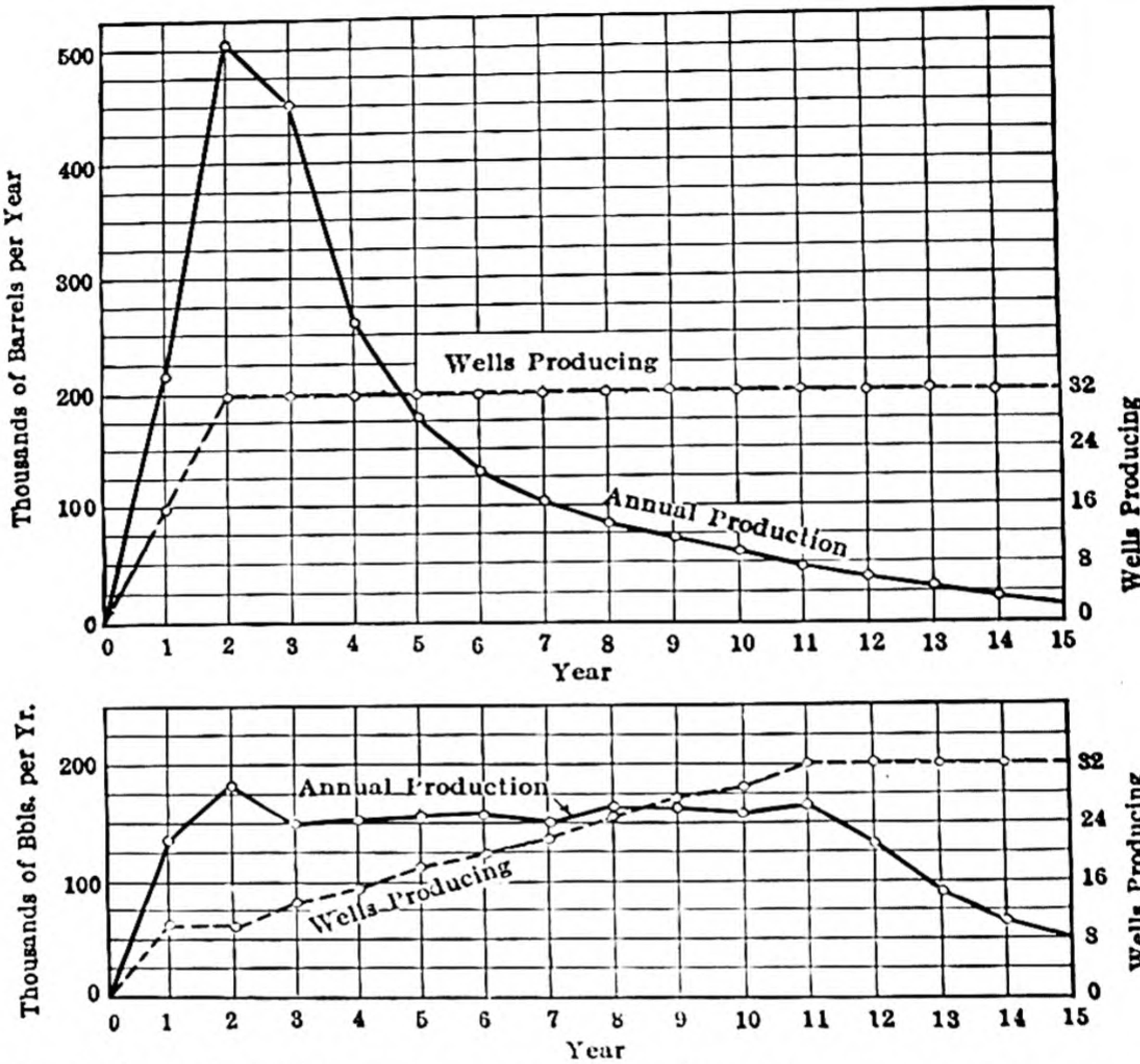


FIG. 18.—Estimated production of an oil property with rapid development (upper graphs), and with slow development planned to maintain uniform output (lower graphs).

NOTE: In each case wells are assumed to be so spaced that they have equivalent initial productions and decline rates.

facilities are greatly overtaxed during the early years, usually necessitating equipment of the property on a scale far in excess of what is required during the later years. Furthermore, when this plan of development is followed there is some possibility, in restricted markets, of overproduction during the early period, which reacts to depress prices, so that the gross return will be somewhat reduced by a lower average selling price per barrel of oil.

Although the maximum amount of oil is secured by drilling all the wells at once, such a program is often impracticable since the drilling

of a large tract must necessarily extend over a number of years. The physical difficulties of road building, rig construction, securing and distributing water supply, camp construction, etc., must precede drilling. The cost of duplication of well-drilling equipment necessary for an intensive drilling program and the provision of working capital for the drilling of many wells at the outset of operations are often prohibitive. The producer usually finds it expedient to finance a part of the cost of developing the property from its production; hence a few wells are drilled first and placed on production, and new wells are added as rapidly as finances and working conditions permit.

Most operators prefer to bring the production rapidly up to a predetermined daily production which will provide a suitable return on the investment and then discontinue further drilling until such time as the wells begin to decline. Thereafter, new wells will be drilled at a rate just sufficient to maintain the production at the desired level (see lower graphs, Fig. 18). This plan results in a uniform rate of production throughout the greater part of the life of the property, and the disadvantages of an intensive preliminary development campaign are largely eliminated.

The development of an oil property may be conducted according to either of several plans. A common method is that of drilling rows of wells, blanket fashion, across the property from proven territory to unproven territory. This plan gives maximum insurance against the drilling of dry holes when it is not certain that the entire area beneath the property is productive. It also offers opportunity for securing necessary information on structural and subsurface conditions for new locations before drilling is begun; that is, geological surmise, based on data from wells only one row distant, is relatively certain in comparison with estimates projected to remote locations in untested territory. A somewhat similar plan is that of drilling progressively outward from productive test wells as centers.

Another method of development involves the preliminary drilling of widely scattered wells at some uniform spacing (say 40 acres per well); then, after this primary system of wells has been completed, intermediate wells are drilled at a smaller interval calculated to give the most economic extraction. This plan has three distinct advantages: (1) the initial productions of scattered wells are, as a rule, considerably higher than those attained by the usual spacing; (2) production from widely spaced wells is better sustained than that from wells closely spaced; (3) final decision as to the ultimate spacing and disposition of wells can be deferred until fairly complete information is available on which to base computations of economic spacing. However, the secondary system of intermediate wells will be deprived of the higher gas pressures and will be relatively small producers, owing to deferment of the period of drilling

and interference from the primary wells. The ultimate production per acre is therefore lower when this plan is followed. It is evident, however, that early wells in isolated positions having relatively high initial productions followed by several years of sustained production will during these years yield to the producer greater and quicker returns than would the same number of closely spaced wells which are as expensive to drill yet have a lower average yearly production. The loss in ultimate recovery of oil may therefore be compensated by the earlier return on the investment, elimination of the possibility of drilling too closely and a better final spacing of the wells based on production data from the primary wells.

Examples illustrating the greater productivity of widely spaced, isolated wells may be found in every oil field, but the following data given by Cutler[7] are representative:

> During the 5-year period, 1913 to 1917, the average yearly initial production of 24 isolated wells in the Buena Vista Hills area, California, was 260,000 bbl., while during the same period that of 104 offset wells was 172,000 bbl. per year; that is, the initial productions were 50 per cent greater for isolated wells than for closely spaced wells. If we assume a drilling campaign which would permit isolated wells to produce 3 years before being offset, the average isolated well, having an initial yearly production of 260,000 bbl., will produce 567,000 bbl. according to actual production records. During the same 3-year period, the average offset well with an initial yearly production of 172,000 bbl. will produce only 345,000 bbl., showing a gain for the isolated well of 222,000 bbl. This indicates the gain in early recovery due to isolation in the Buena Vista Hills area.

The production decline of widely spaced wells is accelerated when their drainage areas are encroached upon by interspaced wells. Hence, the benefit to be derived by drilling scattered wells is negligible if it is followed by rapid drilling of interspaced wells.

Importance of Timely Development

Early in the development of every oil field, owners of tracts within the prospective area are confronted with the necessity of deciding when the various wells shall be drilled and, within the limitations of proration restrictions, the most advantageous rate of production and the economic productive life period of the property. Under competitive conditions, there are powerful incentives which compel the operator to drill and produce his wells as rapidly as possible. Maximum ultimate recovery is secured by systematic and timely drilling of wells. This is true whether the field is producing under "water drive" or "gas drive," but especially in the latter case. Where expulsion of oil from the reservoir rock is primarily by gas expansion, the early wells enjoy the advantages of high reservoir pressure and greater production time, and their initial and ultimate productions are substantially greater than those of later drilled

wells. In unrestricted fields, delay of even a few months may mean substantial losses for the later drilled wells. In water-drive fields the time factor is not so important, for reservoir pressures are substantially maintained; yet, even under this condition, early completion of wells is important. Each day's loss of producing time means reduced ultimate recovery in competition with other earlier drilled wells.

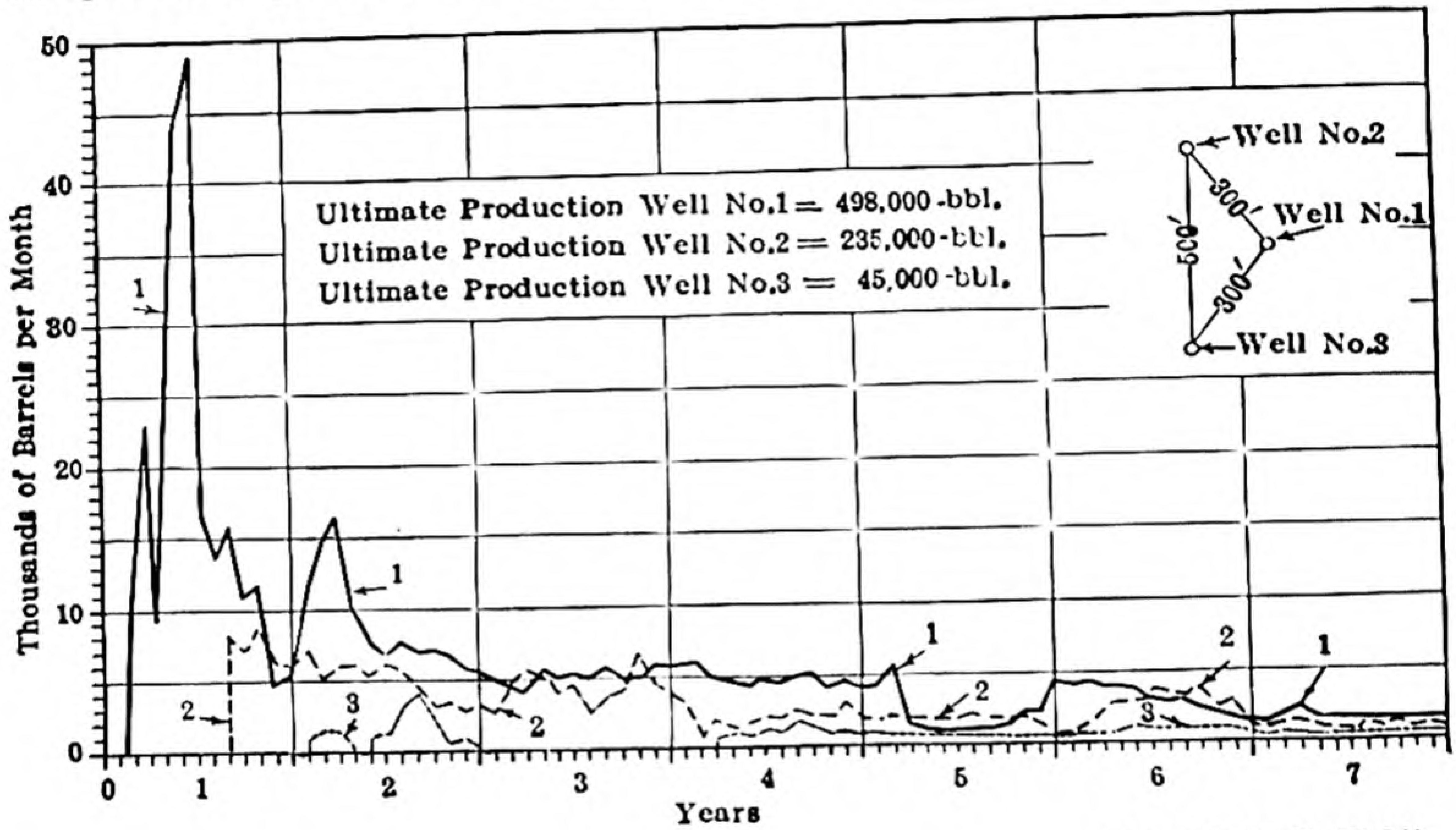
Questions of market outlet and selling price of the oil and gas are, of course, of vital importance. Time is necessary to provide pipe-line outlets from a new field; purchasers may not be immediately at hand and ready to absorb large amounts of oil and gas resulting from many wells in "flush" production. Surplus production in excess of needs of the tributary market will require storage of oil and perhaps waste of gas, both of which mean economic loss.

An important consideration with many operators is the availability of capital with which to drill early wells in a new field. Until the potentialities of a prospective area are determined, drilling expenditures present greater financial hazards. Until field limits are determined, there is always the possibility that a costly edge well will be found "dry." Some operators prefer to let others do the pioneer work of "blocking out" productive acreage before planning development programs for their own properties. Bank officials are often reluctant to lend capital for the development of outlying properties in new fields, and operators are compelled to adopt a conservative drilling program in which the profits on production of early wells contribute capital for the drilling of later wells. Indeed, the early, simultaneous drilling of all of the wells on a property which, from some points of view, would theoretically be most advantageous, is seldom practically feasible. Some of the wells on any property of considerable size must of necessity be later drilled wells; but the intelligent operator will so plan his operations that these will be interior locations in areas that will suffer as little drainage as possible to earlier drilled wells.

In fields where gas pressure is the primary expulsive force operative, maximum ultimate recovery of petroleum requires prompt and complete development of the entire oil-bearing area, once the discovery well has entered upon its productive life; in areas where there has been considerable delay, we may expect to find an important supply of residual oil. The operator who fails to maintain the pace set by his neighbors, or who is unable to finance the rapid development of his property, not only loses some of his oil to his more active neighbors but also ultimately leaves oil in the ground which neither he nor his neighbors can secure; that is, oil that is left in the productive formation gas drained and without motivating force to bring it into the wells. The oil producer who merely protects his boundaries by offsetting neighboring line wells, leaving

his interior locations to be drilled in later years, likewise suffers a loss of a large part of the potential production that his wells might have secured had the entire property been fully developed at an earlier date.*

Field Studies of Losses Resulting from Delayed Development.—In connection with litigation incidental to the efforts of the U. S. Government to clear land titles in the California naval oil reserves and on lands withdrawn from entry pending passage of the Mineral Land Leasing Law of 1920, studies were made of the production records of several hundred wells in an effort to determine their radius of influence and the losses resulting from delayed development. In this investigation, interest was centered upon small groups of wells and offset couples one or two "locations" apart, in



(*After J. H. G. Wolf.*)

FIG. 19.—Production graphs of three contiguous wells in the Midway field, California, illustrating advantage of securing early production in an undrilled area.

order to secure approximately uniform conditions permitting of legitimate comparison of production records. In some instances the production records of individual wells were available, offering a means of comparing the decline characteristics of wells in "influenced" and "uninfluenced" territory. Complete well logs and histories were also provided, and, in the comparisons made, the only records used were those in which the productive sands were well defined and apparently continuous and the source of the oil was definitely known. In each case the ultimate production of the well was estimated by the production-decline-curve method.

The greater recoveries secured from the earlier drilled wells stand out in striking contrast with the relatively small recoveries obtained from later drilled wells. For example, in Fig. 19, well No. 1 was drilled 7 months before No. 2, and No. 3, 5 months later than No. 2. Well No. 1 will ultimately produce 2.12 times as much oil as No. 2 and more than 11 times as much as No. 3. This group of wells is typical of many others that were examined in the course of the field studies. Areas in two different fields were included in the investigation. Although the results were widely variable

* UREN, L. C., Importance of Time in Determining Results of Oil-field Exploitation, *Petroleum Engr.*, January, 1944, pp. 116–122.

when wells producing under different conditions were compared, the data are sufficiently similar to permit of drawing certain general conclusions which, it is thought, represent the results to be expected under average conditions in the Coalinga and Midway fields of California. Figure 20 shows the average loss of a later drilled well for varying intervals of time between completions of earlier drilled and later drilled wells. The graph indicates, for example, that if a well is drilled within gas-drainage radius of another well and is drilled, say, 20 months later, it will produce only 50 per cent as much oil; and if drilled 45 months later, it will produce only 30 per cent as much oil

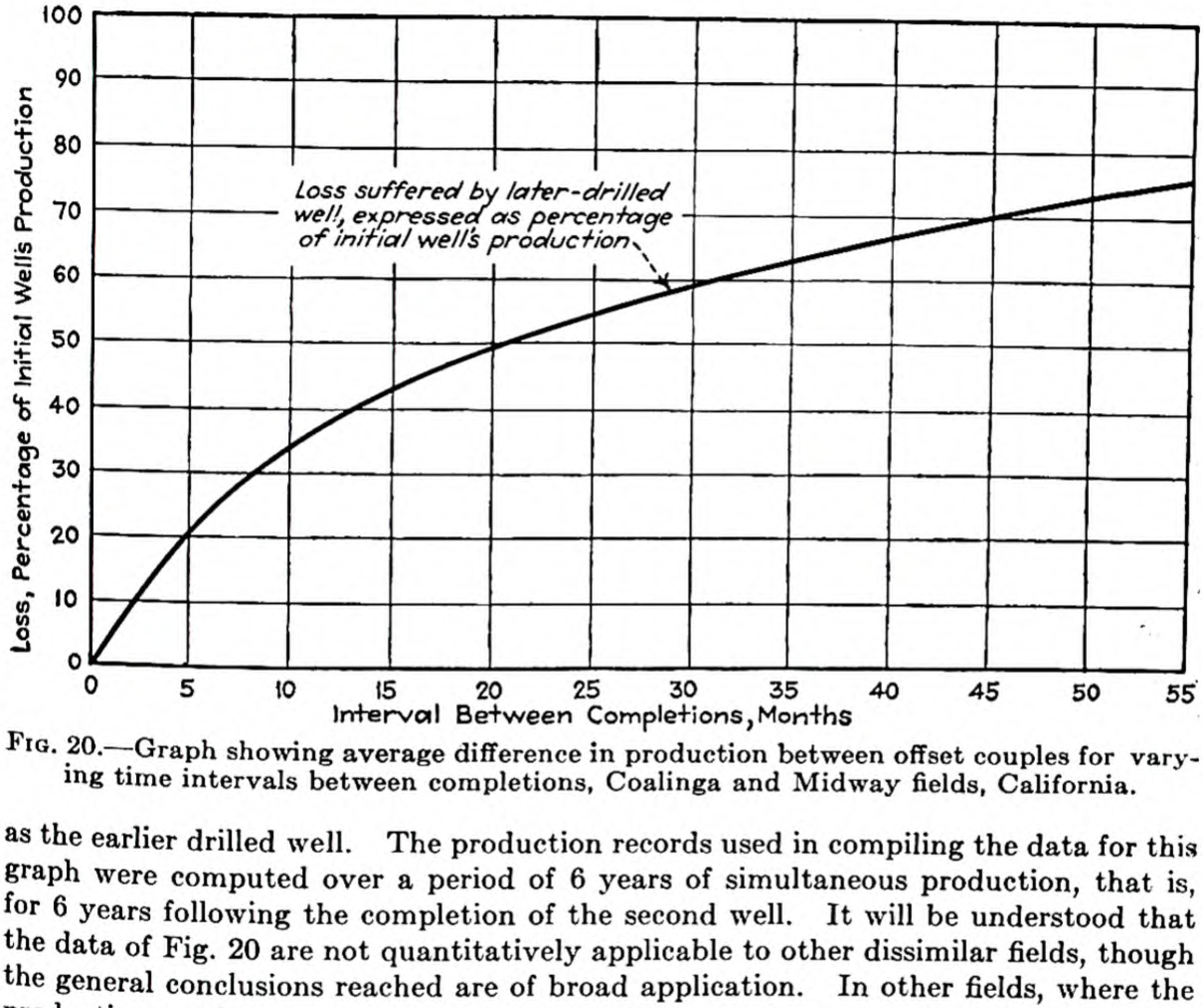


FIG. 20.—Graph showing average difference in production between offset couples for varying time intervals between completions, Coalinga and Midway fields, California.

as the earlier drilled well. The production records used in compiling the data for this graph were computed over a period of 6 years of simultaneous production, that is, for 6 years following the completion of the second well. It will be understood that the data of Fig. 20 are not quantitatively applicable to other dissimilar fields, though the general conclusions reached are of broad application. In other fields, where the productive sands may be thicker and of different texture, or where the initial gas pressure and viscosity of the oil vary materially from conditions in the fields in which the studies were made, we should expect a different loss ratio. The results clearly indicate the importance of timely drilling and serve to give a quantitative impression of the magnitude of losses resulting from failure to achieve timeliness and uniformity in field development. They also suggest a possible method of analysis in making estimates of residual oil content of partly depleted oil lands.

SPACING OF OIL AND GAS WELLS

One of the most important problems confronting the owner of undeveloped oil- and gas-producing acreage is that of determining the number of wells to be drilled to realize maximum profit. In approaching this problem, one must remember that the objective of the operator is not necessarily to produce the greatest volume of oil that the property is

capable of yielding, but rather to realize maximum profit; and usually this is achieved with something less than the maximum possible ultimate recovery. Well spacing is not a matter upon which it is safe to generalize. The physical and economic conditions presented in each case should be considered carefully before intelligent decisions may be reached. Different areas in the same field may require different spacings for best results. A development program suitable for a property exploited under competitive conditions will naturally differ from that appropriate for the same property when it is situated in a unitized field, or in a field where cooperative principles are to govern. One must plan the development program in accordance with his concept of the character of drainage operative. A program appropriate for a water-drive field would differ markedly from that suitable for a field where gas energy is furnishing the expulsive force. The spacing interval in a gas-cap area or in a "distillate field" is quite unlike that appropriate in areas where the reservoir rock is oil saturated.

Because of the great number and complexity of the variables that enter into this problem of determining the economic number of wells, most oil producers have been content to follow precedent, adopting some arbitrarily conceived spacing program which no doubt has in many cases resulted in lower profits than might otherwise have been realized. The development program is often dictated by some ill-advised neighboring operator, competitive considerations replacing scientific and economic drainage principles. In most fields, custom has decreed a certain spacing of wells, or the allowance of a certain drainage area per well; but investigation will show that, in most cases, in fixing the interval between wells, operators have merely followed a practice with which they had become familiar in other fields or districts. Thus, a common interval between wells in many fields is 660 ft., but this merely resulted from the fact that one well in the center of each 10-acre tract provided such spacing, and 10-acre tracts are convenient units in buying and leasing land. If proper consideration is given to drainage principles and related economic factors, this interval might be found appropriate in some cases but grossly in error in others.

Drainage Principles Governing Spacing of Wells.—The expulsive forces operative in overcoming resistance to movement of fluids through the reservoir rock and propelling them toward the well outlets may be created by edge-water pressure, expanding gas and gravitational force. All fields may be classified in two categories insofar as the influence of the expulsive forces is concerned: (1) fields in which edge water encroaches as rapidly as fluids are withdrawn from the wells, so that the formation pressure is substantially maintained, and (2) fields in which edge water does not encroach or does so less rapidly than reservoir fluids are withdrawn, so that formation pressure declines as the reservoir is depleted. The first type of field is often called a "water-drive field," or one under "hydraulic control." In the second type of field,

expanding gas furnishes the expulsive force and for this reason it is often referred to as a "gas-drive field" or one under "volumetric control." Gravitational force is always operative and may at times exert an important influence on the efficiency of drainage, especially in the latter phases of depletion of a reservoir where expanding gas is furnishing the primary expulsive force.* The general plan adopted for the exploitation of an individual field will naturally depend upon which of these types of control is operative.

Where the field is under hydraulic control and the reservoir rock is highly permeable and continuity of pore spaces permits rapid equalization of pressures, wells may be widely spaced without adversely influencing the ultimate recovery. Late completion of wells will not greatly influence their initial production and rate of production; however, delay in drilling must diminish their ultimate production. It has often been suggested that, in such a reservoir, one well situated at the crest of the structure would in time produce all of the drainable oil. Additional wells need be drilled only when competitive conditions exist between different tracts producing from the same reservoir, or where it is desired to produce at a more rapid rate than is possible with a single well.

Where the edge water is stationary or unable to enter the reservoir as rapidly as fluids are produced, quite a different situation exists. Expanding natural gas under pressure furnishes the active expulsive force and, as gas and oil are produced, the formation pressure diminishes. Where the volume of the reservoir remains constant or is not greatly altered by depletion, it is probable that there is some optimum number of wells or some particular spacing interval that ultimately will result in production of the maximum quantity of oil. Where gas energy is furnishing the expulsive force, the interval between wells may have an influence on the effectiveness of oil recovery as a result of inefficient application of gas energy in moving oil through the reservoir rock, and this may operate disadvantageously in cases where the wells are widely spaced. At points remote from the wells, where fluids are moving slowly through the reservoir rock, gravitational force tends to segregate the gas from the oil; thus gas may escape to the wells through oil-drained spaces without doing useful work in moving oil. Gas drainage of this sort may occasion serious wastage of reservoir energy that could be largely avoided by closer spacing of wells and rapid production of oil.

Muskat[27] reaches the conclusion that in a gas-drive field, from a strictly physical viewpoint, the percentage recovery is independent of the well spacing and is uniform throughout the reservoir at all distances from the wells. This conclusion, however, ignores the probability of gas slippage and rests upon the assumption that no residual pressure gradient exists within the fluids in the reservoir rock, and that infinite time is available for the depletion process. These conditions are not realized in practical field exploitation.

Generally speaking, it would appear to be inefficient to force oil to flow through highly resistant communicating pore spaces of the reservoir rock to a distant well outlet. The smaller the distance that the oil has to move through the reservoir rock, the less will be the consumption of reservoir energy and the greater will be the efficiency of energy utilization. However, the consumption of reservoir energy is not directly proportional to the distance traversed, for conditions of radial flow require that the greater part of the energy be consumed within a few feet of the wall of the well. Pressure loss and energy consumption are proportional to the rate of

* A more detailed discussion of the principles governing drainage of petroleum from its reservoir rocks will be found in Chap. I of the companion volume, "Oil Field Exploitation."

flow of fluids and, in radial flow, the rate of travel through the reservoir rock is so low at points remote from the wall of the well, that the pressure loss and energy consumption are negligible in comparison with losses near the wall of the well. Thus, more energy is consumed in moving oil through the 3 ft. of reservoir rock immediately adjacent to the wall of the well than through the next 300 ft. Only 10 per cent more pressure is necessary to force a given quantity of oil through a radial flow system 600 ft. in radius than through one of 330 ft. radius. From the energy standpoint, one might conclude from these statements that the interval between wells is of little consequence in its influence upon oil recovery.

Most authorities adhere to the orthodox view—seemingly confirmed by field data—that in the vicinity of the wells, high percentage recoveries are secured, while at points remote from the wells the reservoir rock is left more highly saturated. There would appear to be ample reason for this expectation, for if movement of oil through the reservoir rock results largely from the "scrubbing" effect of gas bubbles moving through the drainage channels, this effect would be accentuated in the vicinity of the wells where more gas passes and where flow velocities are higher.

Is There a "Drainage Radius"?—Some authorities have reasoned that fluids in the reservoir rock about a well are restricted to a definite distance over which they may move toward the well under given reservoir conditions, and that wells should be spaced no more than twice this distance apart; otherwise, drainable oil will be left in the reservoir. This appears to be a misconception, for studies have indicated that theoretically—in a physical sense—no limitation should be placed upon the distance over which fluids may move. This seems clear, at least, in the case of wells producing in a field under water drive. Here the formation pressure is sustained, the pore spaces of the reservoir rock are always saturated with oil or water and there is always a pressure differential capable of causing flow into the well. Oil will eventually reach the well in such a reservoir, no matter how remote.

In gas-drive fields also, it seems probable that fluids may move toward the wells over indefinite distances. Flow from the formation into the well necessarily requires some movement of fluid through all surrounding strata, though it must be admitted that at remote points the motion may be so slight as to be scarcely perceptible. In one sense, a well producing under gas drive may be said to have an oil-drainage radius if this is defined as the maximum distance over which oil may move toward a well and eventually be produced by that well. However, this is a lesser distance than the radius of influence of the well; during the early period of drainage, oil tributary to a well may move toward it yet, because of gas slippage and pressure depletion, never be produced. In this connection, it is important to note that gas may flow toward a well and eventually be produced over a much greater distance than the associated oil. Thus, a well may be considered to have a gas-drainage radius capable of draining gas and reducing formation pressure over large areas, perhaps throughout the entire reservoir. Areas too remote possibly to yield their oil to a well may yield their gas, and later drilling in these more remote areas will find the reservoir rock well saturated with oil, but largely drained of its gas energy and therefore producible only at very slow rates.

Time is necessarily a factor in any consideration of drainage radius. If a well could be operated forever, we might hope eventually to produce oil from remote areas. However, there is a lower limit to the profitable rate of production for every well, and unfortunately the minimum profitable rate is such as will leave much of the original oil content economically unrecoverable where wide spacing is practiced in a gas-drive field. Only in gas-drive fields may wells be considered to have a natural drainage radius, and then only in the sense that time and economics interpose conditions that, from a practical point of view, determine an area of drainage influence.

Influence of Lithologic Properties of the Reservoir Rock on Well Spacing.—The permeability, porosity, texture, degree of cementation and other lithologic properties of reservoir rocks vary widely and should doubtless be given careful consideration in any study of well spacing. In highly porous reservoir rocks, per-acre yields will be larger than in rocks of low percentage porosity, and wells can be more closely spaced and still "pay out." Permeability is most important, for if the resistance to flow offered by the reservoir rock is high, the rate of recovery on a per-well basis will be slow, and to drain a property within a reasonable time wells must be closely spaced. Wells in "tight" formations may quickly reach a rate of production insufficient to pay operating costs, yet the surrounding reservoir rock may still be well saturated with oil. Pressure gradients, though still high, are incapable of yielding production at commercial rates.

Some authorities object to wide spacing of wells on the theory that in many fields the reservoir rock is widely variable in texture, even lenticular, with highly permeable sand lenses interlaced with shaly sands of very low permeability, yet all portions of the reservoir may be well saturated with oil. When wells are drilled, oil in the more permeable portions will be quickly drained, but the less permeable portions will yield their oil much less freely. Edge water may quickly find its way through the more permeable, oil-drained portions of the reservoir rock, thus inundating the interstratified, less permeable beds. It is believed that under such circumstances a larger percentage of the recoverable oil will be secured if the wells are closely spaced than if they are widely spaced. It seems reasonable that block faulting, stringers of secondary minerals deposited in small fissures, shale "partings," cross-bedding and other irregularities in the strata comprising the reservoir rock may prevent free flow of fluids throughout the reservoir; that certain areas in the field are, in effect, isolated from other areas; and that a widely spaced pattern of wells may leave some of these areas undrained. Close spacing of wells in such circumstances would give greater assurance of a high percentage recovery of the drainable oil.*

Influence of Geologic Structure and Structural Position on Well Spacing.—Geologic structure influences oil and gas accumulation and drainage in many ways and should be taken into account in planning a development program. Several different types of geologic structure are productive of oil and gas, each of which presents its own peculiar problems of well location and spacing. Position on structure is also an important consideration; thus, a property situated at the crest of a structure may require a different plan of development than another situated on its flank near the edge-water line.

An accumulation on domal or anticlinal structure, producing under hydraulic control, if operated as a unit, may yield a high percentage recovery if exploited by a few widely spaced wells situated along the crest of the structure. Wells in this position will produce throughout the economic life of the field and will not be flooded with edge water until nearly all of the available oil has been produced. However, if the field is divided into competitive tracts, the owner of an "edge" property would find it to his advantage to drill closely spaced wells in order to avoid loss of oil beneath his property to up-dip wells. To prevent up-dip drainage, wells should be more closely spaced in the direction of the strike of the beds than in the direction of the dip.

In a field where oil is expelled from the reservoir rock by gas pressure and the formation pressure declines as exploitation proceeds, there is often a gas cap at the crest of the structure. If there is no primary gas cap at the structural crest, one is

* UREN, L. C., Recent Progress Toward Understanding of the Well-spacing Problem: Physical Conditions, *Petroleum Engr.*, September, 1943, pp. 118–126.

likely to form as a result of depletion and gravitational segregation of residual gas and oil still remaining in the reservoir. In a gas-cap area, wells should be widely spaced, if drilled at all. Production should be taken from down-dip wells, so situated that they will drain as little gas as possible from the crestal area. Wells should be spaced in accordance with some uniform pattern that will make approximately equal areas of reservoir rock tributary to each well. Because of the greater surficial area of reservoir rock on steep-dipping flanks, wells may logically be more closely spaced with reference to the horizontal surface plan, in the direction of the dip of the beds than in the direction of strike.

Where a reservoir is highly permeable and edge water is stationary or advancing very slowly, gravity may slowly drain the residual oil from the crestal areas, concentrating it toward down-dip areas. Wells situated on the lower structural flanks may thus continue to produce oil after crestal wells have ceased to produce anything but gas. Where such conditions exist, wells may be more closely spaced in areas near the edge-water line than in the crestal area. If the field is exploited as a unit, a single row of closely spaced wells near and paralleling the edge-water line may efficiently drain the entire structure of its oil.

Economic Considerations Governing Well Spacing.—Oil fields are exploited not so much to produce oil as to earn profits. Maximum profit is realized in exploitation of an oil-producing property when the summation of present values of the differentials between price of oil sold and cost of oil produced is a maximum. It is apparent that cost, price, time of production, the interest rate earned by capital and the quantity of oil produced are factors in determining profit. All these variables except the interest rate are influenced by the distance apart at which the wells are spaced. For each well drilled, the operator gains a production unit and the greater the number of production units, the greater will be his facility of control of production. If a competitive situation exists, close spacing of wells on his property will enable the operator to secure more of the production of the pool than his neighbors who have been content with wider spacing. If, on the other hand, operators are restricted in their right to produce by proration limitations or by cooperative or unit agreements which limit each operator's right to the oil within his own land boundaries, then the operator with closely spaced wells will enjoy no advantage over his neighbors but will nevertheless profit by better control of the rate of production from his own property.

The cost of producing a barrel of oil comprises items representing the cost of well drilling and intangible development expense, operating cost including the cost of well operation and maintenance, depreciation of plant, general and administrative expense and depletion and royalty charges. Most of these items are markedly influenced by the rate of production of the wells which, in turn, is influenced by the well spacing. Wide spacing of wells generally results in a greater average per-well rate of production than close spacing.

A large part of the cost of field development is represented by the cost of drilling wells. Close spacing of wells results in high development costs and smaller profits unless the higher cost is offset by production of more oil or production within a shorter period of time. A well must repay its capital cost and the cost of operation before it may earn profits; hence, the "pay-out" status of a well is an important consideration. A well must have drainage command of a sufficient volume of oil that can be produced at a profit and within an interval of time that will enable it to return its development cost. Close spacing of wells permits of more rapid recovery of the available oil and, within limits, greater over-all recovery, both of which make for greater financial income. However, this greater income may be more than offset by the greater cost of the closely spaced wells. A balance must be sought between

these opposing factors and it would appear that there is some optimum number of wells that will yield maximum profit.

In approaching the problem of determining the number of wells that should be drilled on a given tract, the operator's primary objective will be to establish a spacing program that will confer a maximum present value on his property. Each well drilled will involve a certain capital expenditure which may be rather closely estimated. The cost per foot of drilling increases with the depth to which drilling must be conducted. The nature of the formations to be penetrated and the casing program imposed by subsurface conditions will also have an important bearing. Wells in hard formations will be more costly to drill than wells in soft, easily drilled formations. Heaving shales and caving formations may also occasion slow progress and high cost.*

The cost of operating wells after they have been completed may represent a large element of oil-production cost, particularly when the wells must be mechanically pumped. The rate of production per well has an important influence upon the unit production cost, and from the standpoint of cost per barrel it is advantageous to keep the rate of production per well as high as possible. High per-well yields are obtained by wide spacing. On the other hand, close spacing results in more rapid production of the available oil and shorter operating life for the wells. A shorter economic life means smaller over-all per-well operating cost for a producing property, but this is ordinarily offset by the increased cost of operating the greater number of wells that close spacing requires. Well-operating cost increases with the depth from which production is secured and is governed also by conditions that influence well maintenance and equipment depreciation. With deep wells or wells that require high maintenance expense, wide spacing is more profitable.

The selling price of oil, which, with production cost, determines the profit to be derived from field exploitation, is widely variable and has an important influence on the spacing and pay-out status of wells. High-priced oils permit of closer spacing of wells than low-priced oils. High-priced oil permits of profitably operating wells for lower daily yields, enables a larger number of wells on a given property to "pay out" and hence encourages close spacing of wells. Low-priced oil, on the other hand, may be profitable only when wells are sufficiently spaced to yield their product at suitable rates.

A dollar due at some future time is not worth its face value today. Present-day values of future income are discounted values resulting from application of an interest charge reflecting the earning capacity of capital over the period of deferment. Money in the bank or invested in industrial enterprise earns interest. Oil in the ground earns none. Furthermore, oil in the ground is subject to heavy taxation. Hence, there is financial advantage in early recovery and sale of oil and gas reserves. The shorter the period of realization, the greater will be the present worth of the oil-producing property, and rapid recovery is achieved by close spacing of wells. Loss due to deferred realization on oil and gas values may be substantial when a high rate of interest is involved, as is appropriate in a speculative industry like oil and gas production. Discounted at 10 per cent, $1 due 5 years hence is worth only 62.1 cts.; 10 years hence, only 38.6 cts. The penalty for delay in production is heavy and will sometimes more than offset the cost of drilling and operating a number of additional wells that will materially reduce it.

A large part of the working capital of an oil-producing company is invested in the drilling of wells. This capital must be amortized out of profits and a reasonable

* UREN, L. C., Recent Progress Toward Understanding of the Well-spacing Problem: Economic Considerations, *Petroleum Engr.*, November, 1943, pp. 116–122.

rate of interest earned on the outstanding or unredeemed principal before operations may be said to be profitable. Thus, a well is said to "pay out" when it has returned its original cost with a proper rate of interest on unredeemed capital, plus the cost of operating the well during the pay-out period. For example, a well costing $125,000 to drill and 40 cts. per barrel of production to operate, and restricted by proration requirements to 35,000 bbl. per year will, if oil sells for $1 per barrel, pay out in its ninth year if the interest cost of capital is 8 per cent. During this time, use of the capital expended in drilling the well will cost upward of $51,600. Close spacing of wells, though recovering the producible oil in shorter time, will increase the length of time for the wells to pay out, because of the smaller per-well rate of production and the greater amount paid in interest on invested capital. Widely spaced wells with larger and better sustained productions pay out in shorter time and with a smaller interest charge for use of capital.

It will be noted that the interest cost of capital and the interest cost of deferred production are opposing factors. Interest cost of capital is reduced by wide spacing of wells, whereas the interest cost of deferred production is reduced by close spacing of wells. A balance must be sought between these opposing factors, which will depend upon the interest rate charged, the capital cost of wells, the rate of production and the selling price of oil.

Well-spacing Formulas.—The many different variables involved in the well-spacing problem and the intangible nature of some of them have made the development of an all-inclusive formula exceedingly difficult. Several authors have offered formulas that are useful to a certain extent in analyzing the results of different well spacings in fields where development has proceeded to a point that will permit of determining ultimate recoveries and of estimating what might have resulted had a different spacing program been adopted. What is needed, however, is a formula that will permit of predicting proper spacing in advance of development. Determination of the economic interval between wells in reality presents a group of related problems some of which are not susceptible of accurate analysis with data now available. This being true, we can at present approach a general solution only by a series of approximations. Though a general well-spacing formula is apparently not attainable in the light of our present knowledge, it should nevertheless be eventually possible to formulate the many influencing factors along mathematical lines.*

Field Data on Influence of Well Spacing on Ultimate Recovery.—Instead of placing dependence upon mathematical formulas difficult to understand and of doubtful validity, most oil producers will prefer to approach the problem of determining the economic spacing of wells through analysis of field data. Information is available in the literature, giving the recoveries obtained by different well spacings in several Mid-Continent, Appalachian and California fields, all of which indicate that close spacing of wells is productive of greater per-acre recovery, though the greatest per-well production is secured by wide spacing.

W. W. Cutler, Jr., has assembled data illustrating the effect of well spacing on recovery efficiency in several Oklahoma fields.[7] Table VII gives the results of a study of production data from 134 wells on 23 different tracts in the Nowata district, northern Oklahoma, in areas where three different spacings were used and a considerable variation in initial production of wells was experienced. Table VIII gives similar data for 337 wells on 80 different tracts in the Bartlesville-Dewey district of northern Oklahoma. Results for five different spacings are available here. Cutler has also assembled similar information on 10 tracts with 114 wells on two different spacings in the Speechley Pool, Butler County, Pa. The data presented in these

* Uren, L. C., Theoretical Aspects of Well Spacing, *Nat. Petroleum News*, Jan. 1, 1930, pp. 49–58.

TABLE VII.—EFFECT OF SPACING OF WELLS ON ULTIMATE PRODUCTION IN THE NOWATA DISTRICT, OKLAHOMA

Spacing, acres per well	Initial year's production, bbl.	Ultimate production per well, bbl.	Ratio of ultimate productions per well, per cent	Ratio of square roots of areas drained, per cent	Ultimate production per acre, bbl.
10	6,000	16,900	100	100	1,690
8	6,000	15,200	90	89.5	1,900
6.3	6,000	14,300	84.5	79.5	2,386
10	4,000	12,200	100	100	1,220
8	4,000	10,900	89	89.5	1,366
6.3	4,000	10,300	84.5	79.5	1,717
10	2,000	6,900	100	100	690
8	2,000	6,100	88.5	89.5	766
6.3	2,000	5,700	82.5	79.5	950

TABLE VIII.—EFFECT OF WELL SPACING ON ULTIMATE PRODUCTION IN THE BARTLESVILLE-DEWEY DISTRICT, OKLAHOMA

Spacing, acres per well	Initial year's production, bbl.	Ultimate production per well, bbl.	Ratio of ultimate productions per well, per cent	Ratio of square roots of areas drained, per cent	Ultimate production per acre, bbl.
15	4,000	14,800	.....	.....	987
10	4,000	14,200	.....	.....	1,420
7	4,000	14,000	100	100	2,000
5	4,000	11,300	81	84	2,260
3	4,000	9,750	70	65	3,250
15	2,000	7,700	.....	.....	513
10	2,000	7,770	.....	.....	770
7	2,000	7,770	100	100	1,100
5	2,000	6,100	78.5	84	1,220
3	2,000	5,180	67	65	1,727
15	1,000	3,850	.....	.....	257
10	1,000	3,850	.....	.....	385
7	1,000	3,850	100	100	550
5	1,000	3,160	82	84	632
3	1,000	2,630	68	65	876

tables are arranged to demonstrate a theory advanced by Cutler, in which he states that "The ultimate productions for wells of equal size in the same pool, where there is interference, seem approximately to vary directly as the square roots of the areas drained by the wells." This is equivalent to saying that the recovery will be inversely proportional to the distance that the oil must travel to reach the well; that is, if we use the same amount of energy in each case, doubling the distance between wells secures only half as much oil.[7] Cutler's rule may be expressed in the form of an equation; thus, $P_W = C\sqrt{A}$, where P_W is the ultimate production of a well in barrels, A is the area drained by the well, and C is a constant for a given reservoir. If we accept this rule, if follows that $P_a = C/\sqrt{A}$, where P_a is the ultimate production of oil per acre.[25]

The validity of Cutler's rule has been questioned by many authorities, though it seemingly has the support of field data, at least in certain types of reservoirs and within a certain range of spacing. Cutler himself expressed doubt concerning the universal applicability of such a rule and subsequent studies have shown that in some fields it obviously does not apply. Simple mathematical inspection will show that the rule leads to absurd conclusions when applied to situations where very close spacing is assumed. The rule is, of course, not applicable where edge-water encroachment is furnishing the energy that expels the oil. It cannot be expected to apply where the formations are highly lenticular or are faulted, or where other discontinuities exist. If the pressure loss of oil flowing through a reservoir rock is expressed by D'Arcy's equation (see page 677), it is clear that the assumption that recoveries are proportional to the distance between wells is untrue.*

Although we must reject the Cutler theorem as one of broad, general application, yet it must be admitted that the field evidence submitted by Cutler in support of it is impressive. It is undoubtedly true that for certain types of reservoirs where the reservoir rock is a sand or sandstone of approximately uniform thickness, porosity and permeability, where gas energy latent within the oil is the dominant expulsive force and where wells are allowed to produce without restriction, the rule seemingly applies within the range of well spacing commonly employed in comparatively shallow fields.

U. S. Bureau of Mines engineers have gathered data indicating the influence of well spacing on ultimate recovery in the Mexia-Powell fault-line fields of Texas (see Table IX). The figures given are averages for groups comprising many individual properties, all of which produce from the Woodbine sands under essentially similar conditions. It is apparent that in these fields closely spaced wells secure a larger per-acre-foot yield than widely spaced wells. In the Powell field, studies have indicated that rapid development with an allowance of 2.25 to 2.5 acres per well will show the largest recovery in barrels per acre and percentage recovery, and will give the quickest return of investment. However, the return per dollar of investment will not be so large as from more conservatively drilled areas.[10]

Information is also available on results of wells arranged under different spacings in various zones of the Sante Fe Springs field of California. The sands here are unusually thick, and abnormally high per acre recoveries have been secured. Development has been characterized by highly competitive conditions and the data are of special interest in that few studies of the sort have been made in other "town-lot" fields. Table X gives the results. It will be noted that, although intensive development of the character of that at Santa Fe Springs has been generally con-

* For a discussion of the D'Arcy equation and its application to flow of oil through reservoir rocks, the reader is referred to the companion volume, "Oil Field Exploitation," p. 47.

TABLE IX.—ULTIMATE PRODUCTIONS FOR WELLS OF DIFFERENT SPACING IN THE MEXIA-POWELL FAULT-LINE FIELDS OF TEXAS*

Field	Acres per well	Indicated ultimate oil production per acre-foot
Wortham	3.0	670
	2.2	1,095
	1.9	1,528
	1.8	1,735
Mexia	10.7	268
	7.45	585
	4.5	282
	4.3	880
	3.31	1,051
Powell	4.4	795
	3.7	1,117
	2.9	1,232
Richland	2.66	1,214
	2.15	1,517
Currie	5.80	770

* After Hill and Guthrie in *U. S. Bur. Mines Rept. Inv.* 3712.

TABLE X.—ULTIMATE PRODUCTIONS FOR WELLS OF DIFFERENT SPACING PRODUCING FROM VARIOUS ZONES IN THE SANTA FE SPRINGS FIELD, CALIFORNIA*

Zone	Spacing, acres per well	Ultimate production per well, bbl.	Ratio Of ultimate per-well productions	Ultimate production per acre, bbl.	Ratio of ultimate per-acre productions
Meyer	4.35	424,000	100	97,500	100
	0.66	322,500	76	492,200	505
Buckley	4.44	353,090	100	79,300	100
	1.19	145,500	76	121,900	154
O'Connell	5.71	833,660	100	146,000	100
	.89	295,025	35	331,900	227
Clark	5.0	305,000	100	61,000	100
	.85	136,260	45	159,800	262

* After A. S. Hayes in *Am. Petroleum Inst. Bull.* 209.

demned as uneconomic, close spacing has effected a much greater recovery than normal spacing from the per-acre standpoint. Table X shows, however, that the production figures do not accord even approximately with Cutler's theorem.

A study of recoveries secured by different spacing of wells in the Long Beach field of California also shows that close spacing of wells is in every case productive of the greater per-acre recovery, though the greatest production per well has invariably been attained by wide spacing. Table XI gives the results of this study.*

TABLE XI.—ULTIMATE PRODUCTIONS FOR WELLS OF DIFFERENT SPACING IN THE LONG BEACH FIELD, CALIFORNIA†

Spacing, acres per well	Recovery per well to July 1, 1929, bbl.	Ratio of per-well productions	Recovery per acre to July 1, 1929, bbl.	Ratio of per-acre productions
2.92	266,569	100	91,395	100
0.71	140,399	53	196,558	215
3.23	231,638	100	69,990	100
0.83	227,961	98	273,553	398
3.33	470,685	100	141,206	100
0.87	157,468	33	181,088	128
2.5	206,926	100	82,770	100
1.0	138,050	67	138,050	143
3.0	147,404	100	49,135	100
0.88	137,387	94	155,705	317

† After D. C. Roberts and S. Sweeney, "Petroleum Development and Technology, 1930," Am. Inst. Mining Met. Eng.

Some authorities, while admitting that wells may exert a drainage influence over wide areas, especially under conditions of restricted flow, nevertheless believe that close spacing will result in greater ultimate recovery than wide spacing because of irregularities in stratigraphy and lithology in reservoir rocks that restrict free movement of oil. Nature's methods of sedimentation seldom result in strata of uniform thickness, continuity and permeability. Close inspection of reservoir rocks will usually disclose minor shale "partings," cross-bedding, "stringers" of secondary minerals deposited in small crevices cutting across bedding planes, minor faults and other stratigraphic discontinuities that impede free drainage of fluids.

The foregoing field evidence would appear to confirm the opinion held by many operators that close spacing of wells results in higher per-acre yields than widely spaced wells, at least in competitive fields where gas energy is furnishing the expulsive force and wells are not unduly restricted. In each case, it is evident also, that wider spacing increases per-well recovery, reduces per-barrel cost and yields greater profit per dollar of invested capital. With this latter statement, there can be no disagree-

* UREN, L. C., The Spacing of Oil Wells: Field and Experimental Data, *Nat. Petroleum News*, Mar. 19, 1930, pp. 78–84; Mar. 26, 1930, pp. 61–64; Recent Progress Toward Understanding of the Well-spacing Problem: Field Data, *Petroleum Engr.*, December, 1943, pp. 76–84.

ment, but many authorities do not agree that close spacing will necessarily result in greater per-acre yields, particularly where the rate of production is restricted by proration. They contend that close spacing merely hastens recovery and that excessive drilling may result in wastage of gas energy which actually reduces rather than increases ultimate recovery. In unitized fields, or where close cooperation between operators is possible, wells may be more widely spaced. Greater efficiency in control of reservoir energy possible under such conditions permits of recoveries as great or perhaps greater than those possible with closer spacing under competitive

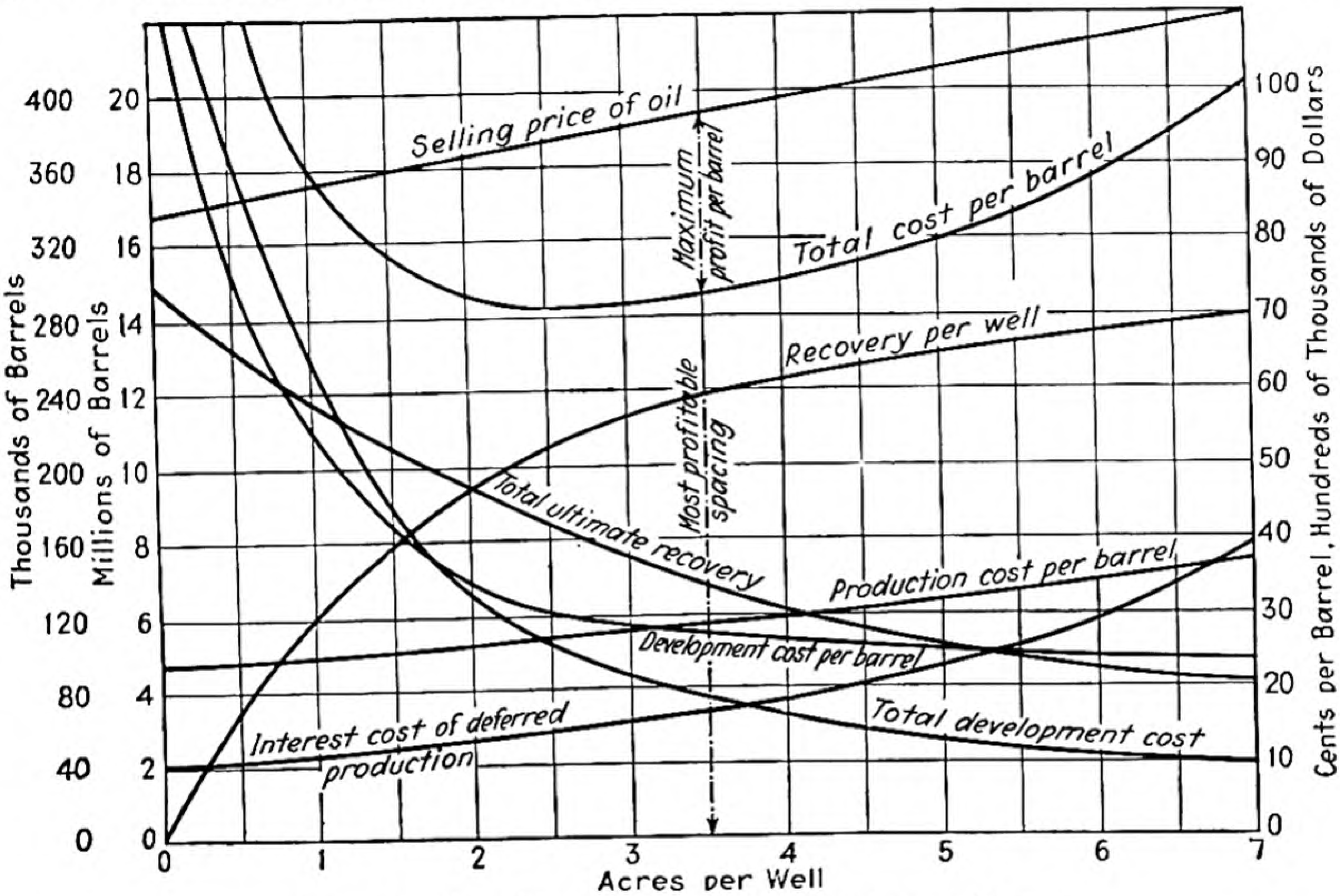


FIG. 21.—Graphic solution of well-spacing problem.

conditions. In unitized water-drive fields, the spacing of wells becomes largely a matter of the rate of production desired and economic considerations are of primary interest. The oil producer, whose interest lies in securing maximum profit from his operations, rather than maximum production of oil, finds the well-spacing problem one to be solved largely by economic rather than physical considerations.

Graphical Analysis of a Well-spacing Problem.—With the aid of production data for several different spacings of wells, such as have been presented in the tables reproduced in connection with the foregoing section, supplemented by cost data that can be readily assembled, it is possible for the engineer to approach the problem of estimating the most profitable spacing of wells by a procedure which we might call "graphic analysis." Figure 21 will serve to illustrate the method: A start is made by plotting points showing production per well and ultimate recoveries per acre for different spacings from such data as are available. The "recovery-per-well" and "total-ultimate-recovery" curves are then drawn through these points, as illustrated in Fig. 21. We then compute points on and construct from known drilling costs the "total-development-cost" curve, and, dividing the total acreage development cost by the equivalent estimated recovery figures, we derive the "development-cost-per-barrel" curve. As might be expected, the unit development cost is shown to increase rapidly as the spacing diminishes. We next construct a similar curve showing

the unit production cost. Total operating cost diminishes as the number of wells to be pumped decreases, but a larger number of wells means a shorter period of operation and a greater total production, all of which tendencies combined result in a slightly increasing unit production cost as the spacing is increased.

Another element of cost that must be taken into account is the interest cost of deferred production which, of course, increases as the spacing increases, owing to the slower rate of recovery. Summation of the ordinates of these three cost-element curves gives points on the "total-cost-per-barrel" curve, which shows a minimum unit production cost, in this case, of 71 cts. at a spacing of 2½ acres per well. This, however, does not indicate the most economic spacing unless the unit selling price of oil is assumed to remain constant. In Fig. 21 the selling price is assumed gradually to increase in future years, and, owing to the slower rate of recovery as spacing is increased, a higher average price is realized. The maximum distance apart of the "selling-price" curve and the "total-cost" curve is attained at a spacing of 3½ acres per well. The cost per barrel for this spacing is shown to be 73 cts. per barrel and the profit, the difference between this and 97 cts., or 24 cts. per barrel. The ultimate recovery per well for this spacing will be about 240,000 bbl., and the total ultimate recovery (for a tract of 120 acres in this case) will be about 6,750,000 bbl. To realize this, we shall have to expend $1,850,000 in development work, or 27 cts. per barrel of oil recovered. The production cost per barrel will be 29 cts. per barrel and the interest cost of deferred production is estimated at 17 cts. per barrel.

With sufficient data, it is possible to analyze any well-spacing problem along these lines and display the results in convenient form for inspection and analysis.[35] In securing additional points on the recovery curves, in the event that sufficient data are not available to construct them, recourse may be had to such formulas as those proposed by Dr. W. P. Haseman[19] and Mr. R. W. Phelps.[28] It will be noted, however, that this method of analysis is useful only in studying the results of production on properties already developed or in course of development and that sufficient data will generally be available only after the operator is already committed to a certain development program, which may or may not be the most economic one. In other words, such a method is useful only in retrospective analyses and does not provide a dependable means of predicting proper spacing for an undeveloped property.

Laboratory Research on the Well-spacing Problem.—Some aspects of well spacing lend themselves well to laboratory study, and, although but little work of this character has been done as yet, it is possible that laboratory research may eventually contribute in an important way to the ultimate solution of the well-spacing problem. The author and his coworkers in the University of California petroleum-engineering laboratories have for some years been conducting recovery experiments in sand-filled pressure-drainage apparatus, which would appear to afford a new method of approach. Though contrary to all the field evidence, one interesting group of experiments has indicated that very close spacing of wells may result in smaller gross ultimate production of oil from a tract of land than will be produced by a fewer number of wells. A possible explanation of this is found in the more rapid depletion of field pressure and the greater wastage of gas energy that attends operation of the larger number of wells. An experimental study of the pressure gradient in an oil-reservoir sand maintained under conditions approximating those in the vicinity of a high-pressure well has been productive of results which permit of predicting the drainage influence of such a well under a given set of conditions with fair accuracy. Description of the apparatus used in these experiments and more detailed narration of the results are reserved for the companion volume of this treatise.*

* "Oil Field Exploitation," pp. 49–52.

Looking toward the development of a practical means of determining the most profitable spacing under a given set of field conditions, it would appear to be possible through experimental research to establish a unit of sand permeability, comparison with which, for a given field pressure and thickness of sand, would at once determine the quantity of oil that could be extracted by a specified method of well operation under any spacing interval that might be adopted. It then remains only to balance cost against revenue to determine the spacing that would be most profitable. It should be possible on this basis, with sufficient experimental and field data as a guide, to estimate from laboratory tests on cores of the oil sand and closed-pressure measurements taken in a single well (before it has been allowed to produce) the proper spacing for wells on the acreage immediately surrounding. As these are drilled, they, in turn, furnish similar criteria for the spacing of wells to be drilled later on adjacent territory. The economic spacing is not properly constant but may conceivably vary widely, even within areas of limited size.

Economic Aspects of Well Spacing.—Losses due to improper well spacing must aggregate truly prodigious amounts from the national standpoint. There are undoubtedly many fields where highly competitive conditions have led to the drilling of more wells than the productive area can properly support. Many wells in the crowded town-lot sections of the Sante Fe Springs and Long Beach fields of California, for example, are so closely spaced that they will never pay out. A high per-acre yield will result from intensive development, but the cost of drilling and operating so many wells will be more than the value of the oil produced. Doubtless, in many closely drilled areas, there will be some profit, though it will be less than it might have been with wider spacing. On the other hand, many of the more conservatively developed fields have been drilled with wells that are too widely spaced for maximum profit. Great areas in Mid-Continent and Western American fields have been drilled with an allowance of 10 acres per well, and yet computations indicate that in some cases profits could have been doubled or tripled by adopting closer spacing. Present information does not admit of anything more than speculation on what the aggregate loss has been from the national standpoint, but rough computations, based on data from a few fields on which results have been assembled, suggest that it is probably greater than the profit that has been realized on all of the oil thus far produced.

Circumstances over which the individual producer has little or no control have contributed in an important way to the financial loss resulting from improper well spacing. The competitive principle in oil-field development is a fundamental difficulty, the influence of which can never be entirely overcome until the industry finds a means of effecting unit exploitation of oil pools. The small size of many competitive tracts, with resulting obligations to offset neighboring activities and protect boundaries, often compels the producer to adopt a spacing program not in accord with his better judgment. Lack of adequate financial resources during the early stages of development, in many cases, prevents exploitation on the most profitable scale. An oversupplied market often compels a less intensive rate of development than economic considerations would otherwise justify. The program of proration and restriction of development activity that has been followed during years of oversupply, while essential from the market standpoint, nevertheless has dictated a development program that in many fields probably means diminished ultimate recovery and smaller gross income than could have been realized if a reasonable price structure could have been maintained without restriction of output. This situation can perhaps best be remedied by the expedient of shutting in all wells and deferring all development activity in flush fields until market conditions favorable for exploitation on the most profitable scale are realized.

Well spacing as a community problem is a matter in which some central agency

should become interested in a substantial way, with the purpose of standardizing spacing practice in all fields on a scientific and economic basis. Losses due to uneconomic spacing of wells have been enormous and will continue until a concerted effort is made to systematize well spacing in new fields along scientific and economic lines and not with respect to property lines. Without doubt, economic well spacing is the most important unsolved technical problem before the present-day oil-producing industry.

Estimating Economic Life of Oil Properties

The economic life of an oil-producing property is that period of time within which, if all oil that may be profitably produced is marketed, a maximum profit will be realized. The estimation of this economic life period is a problem that confronts every oil producer in planning the development program for his property, particularly in determining the maximum rate of productivity that he should strive to attain. Given a certain tract of undeveloped land known to be oil bearing, should all of the wells that the land will support be drilled at once, or would a less intensive program be more profitable? Will it be more profitable to produce as much oil as we can get early in the productive life of the property, or would it be preferable to conserve the bulk of the oil in the ground until some future period? Obviously, the productive life of the property will have an important bearing on estimates of production cost and on the present value of future income to be derived from oil sales.

Estimation of the economic life period of an oil-producing property is a problem that involves the same physical and economic factors that have already been discussed in connection with the well-spacing problem. Indeed, the estimation of economic life is but a different form of the same problem and is subject to the same limitations that were found to apply in connection with the well-spacing problem. The rate of production decline, the cost of production and the selling price of petroleum are mutually interrelated factors limiting the period of economic operation of an oil-producing property. The lower limit of profitable operation is reached when the cost of producing a barrel of oil is equal to its selling price. As the rate of oil production declines, the cost per barrel rapidly increases, but, as the critical period is reached when lifting costs are almost as great as selling price, the economic life may be greatly prolonged by a moderate increase in selling price or decrease in operating expense. Figure 22 illustrates a typical case At a selling price of $1.50 per barrel, the limit of economic well operation is reached during the twelfth year of operation, when the production is 6 bbl. per well per day; if the selling price is increased 50 cts. per bbl., or the cost of production is reduced by a like amount, the profitable life is prolonged by 3½ years; if the price is increased to $2.75 per barrel, the property may be profitably operated for 20½ years.

The graphic method of analysis that was found to be useful in analyzing the factors entering into the well-spacing problem may again be resorted to in making approximate estimates of economic life of oil properties. A typical example will serve to demonstrate the method of graphic analysis as applied to the economic life problem Let it be assumed that the property in question consists of a section of land—a mile square—and that the entire tract is known to be commercially productive by reason

of wells that have been drilled about its boundaries. Decline curves from early wells drilled on neighboring tracts and the known costs of development and operation elsewhere in the field, or in similar fields, permit of approximately estimating the oil recoveries possible from year to year and the production costs for different assumed development programs. From such data it is estimated that if wells are spaced so that there will be 2 acres of land per well, the property will be exhausted in 4 years; if 4 acres are allowed per well, the recoverable oil will be secured in 9 years; if 6 acres, 14 years; 8 acres, 21 years; 9 acres, 26 years. A study of cost data for these different rates of recovery gives the data of Table XII. Estimates of the future selling price of petroleum, based on market trend, indicate the average selling prices per unit of product, which are given in the last column of the table. The second column in the table

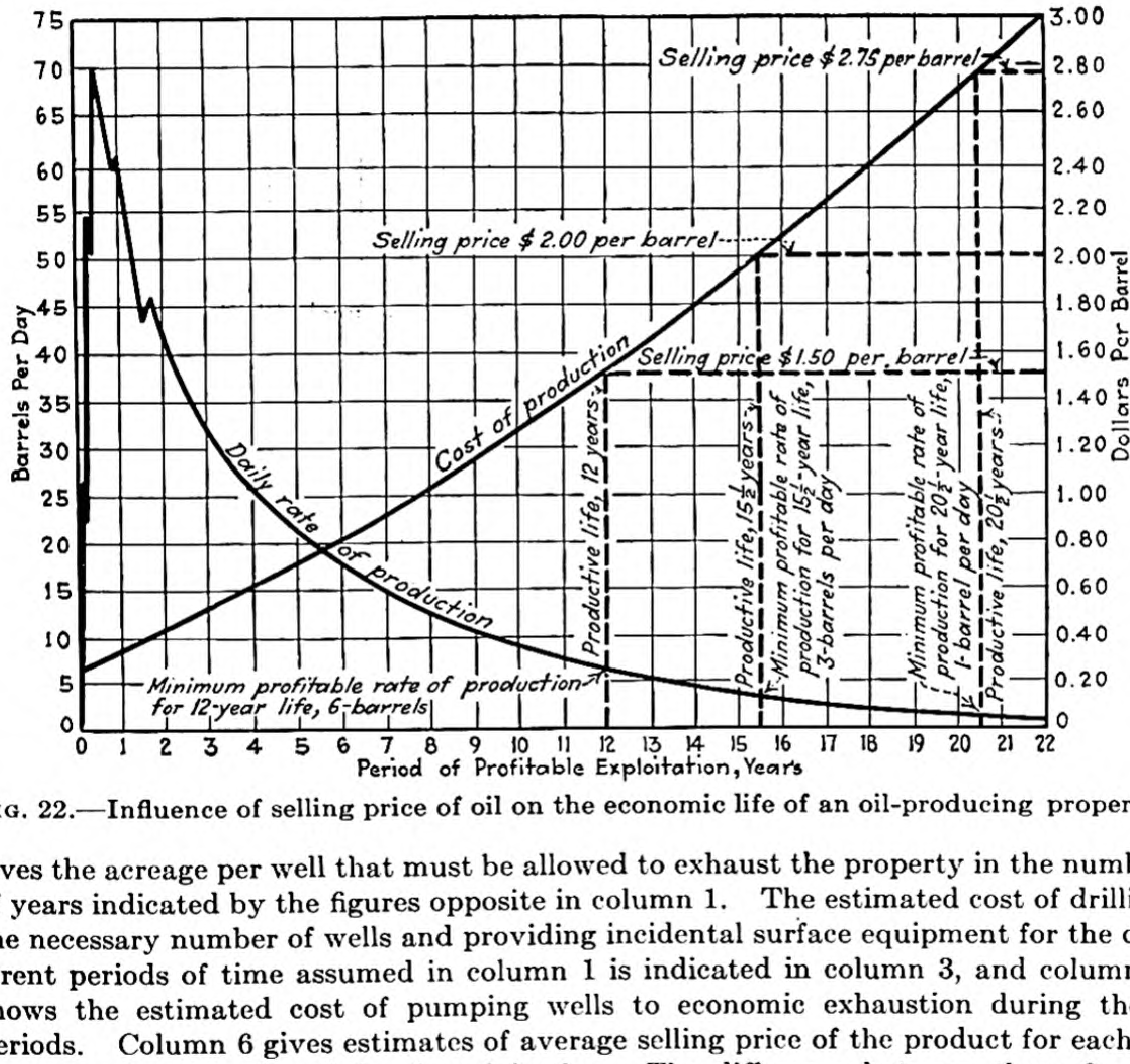


FIG. 22.—Influence of selling price of oil on the economic life of an oil-producing property.

gives the acreage per well that must be allowed to exhaust the property in the number of years indicated by the figures opposite in column 1. The estimated cost of drilling the necessary number of wells and providing incidental surface equipment for the different periods of time assumed in column 1 is indicated in column 3, and column 4 shows the estimated cost of pumping wells to economic exhaustion during these periods. Column 6 gives estimates of average selling price of the product for each of the several assumed periods of exploitation. The difference between these figures representing average selling price and the sum of the figures opposite in columns 3 and 4 gives the average apparent profit per barrel of oil. These figures are discounted by a factor representing the interest loss to determine the "interest cost of deferred production" given in column 5. In making this computation, an interest rate of 10 per cent is adopted and it is assumed that the average period of deferred payment is about one-third of the total number of years necessary for exhaustion given in column 1.

The assumed and computed values given in Table XII are next plotted on coordinate paper as illustrated in Fig. 23. Five points on each curve are sufficient to deter-

mine its entire course with fair accuracy. Graphic addition of the ordinates of "capital-cost," "operating-cost" and "interest-cost" curves determines points on the "total-cost-of-production" curve. The length of ordinate between this latter

TABLE XII.—DATA COMPILED FOR USE IN GRAPHIC SOLUTION OF TYPICAL ECONOMIC LIFE PROBLEM

(1) Number of years necessary to exhaust property	(2) Acres per well	(3) Capital cost of development and equipment per barrel	(4) Operating cost per barrel	(5) Interest cost of deferred production per barrel	(6) Average selling price of oil per barrel
4	2	$1.50	$0.28	$0.03	$1.72
9	4	0.90	0.52	0.15	1.86
14	6	0.65	0.74	0.30	2.02
21	8	0.52	0.98	0.59	2.26
26	9	0.48	1.09	0.67	2.37

curve and the "selling-price-of-oil" curve shows the probable average profit per barrel of oil for any assumed time of exhaustion for the property. It is to be noted that the maximum profit per barrel is realized when the period of exploitation is 11½ years, which is, therefore, the economic life of the property. Intersection of the

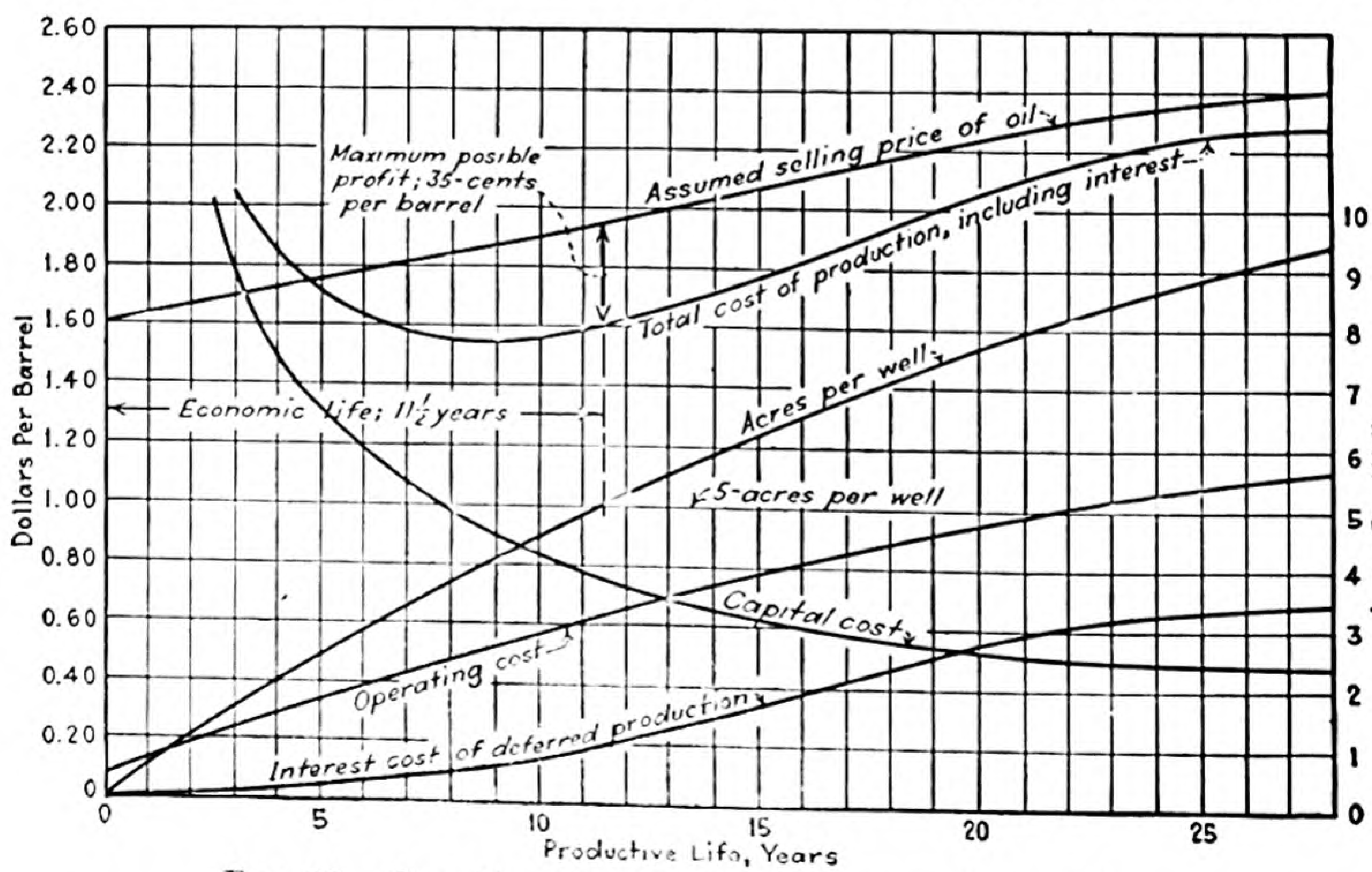


FIG. 23.—Graphic solution of the economic life problem.

11½-year ordinate with the "acres per well" curve indicates the spacing of wells necessary to accomplish drainage within this time.

This method of estimating the economic life of an oil property assumes that the same quantity of oil is ultimately produced irrespective of the spacing of wells assumed. The ultimate recovery, however, is secured in a briefer interval of time

by closer spacing. This assumption is true only so long as the acreage per well assumed does not result in the wells being spaced beyond their natural radius of drainage, thus leaving undrained spaces between wells. This maximum radius of drainage is dependent upon the physical properties of the oil and the lithological and structural properties of the reservoir rock, and its evaluation constitutes a separate problem which must be solved before the economic life period can be estimated.

Further consideration of the graphs of Fig. 23, particularly of the region between the curves representing the selling price of oil and the total cost of production, shows that serious losses are incurred by unduly shortening the productive life. For example, if a 7-year life is assumed, 35 per cent of the potential profit is sacrificed; and if the period of recovery is reduced to 5 years, the profit is only one-tenth what it would be if the property were exploited for the economic life period. An unduly prolonged productive life also reduces the potential profits, though losses do not seem to be so great in this direction. The important influence of increasing oil prices on the period of economic life is particularly worthy of note. If conditions were such that a declining or stationary price structure could be anticipated over the greater part of the period of productivity, a shorter economic life period would result.

Maximum Efficient Rate of Oil Production

There is, for every oil-producing property, a certain optimum rate of production at which maximum profit will be achieved. This is not necessarily the rate that will result in maximum recovery efficiency. Determination of the optimum rate for most profitable operation must take economic considerations into account. In determining the optimum rate for maximum oil recovery, consideration is given only to physical factors governing drainage. Naturally, the oil producer's interest attaches to the former rate rather than the latter. The consumer and the conservationist, on the other hand, are concerned primarily in promoting conditions that will assure maximum oil recovery. Thus, the interests of the producer are at variance with those of the consumer and the public, except that the consuming public is interested in keeping the producer in business. The public interest requires that the producer shall realize profit on his operations, but not necessarily the largest profit.

Because of the difficulty of evaluating certain intangible factors involved, petroleum technologists have not yet devised a means of determining with precision either the optimum rate for maximum profit or the optimum rate for maximum recovery. In water-drive fields, the maximum permissible rate of production for a field will be that which will allow edge water to encroach as rapidly as fluids are withdrawn, thus avoiding serious loss of reservoir pressure and release of gas from solution in the oil. Or, perhaps the optimum rate of recovery will be that which will prevent irregular infiltration of edge water into the reservoir rock and trapping of bodies of undrained oil in the less permeable strata or lenses. In gas-drive fields, it is sometimes assumed that the most efficient rate of production for maximum recovery is that which will result in minimum gas-oil ratio. If this rate is too low to be eco-

nomically attractive, the producer may compromise by adopting a higher rate which will achieve reasonable production efficiency and profit.

For each well at a given time in a gas-drive field, there is a certain ratio existing between the rates of gas flow and oil flow through the reservoir rock into the well that will result in maximum efficiency in oil recovery, but this is not constant and it will vary as drainage proceeds and with change in the relative amounts of gas and oil in the pore spaces of the reservoir rock. Naturally, such a ratio will vary widely for different wells and in different areas in the field. Determination of this most efficient rate involves analysis of a variety of complex variables, the evaluation and formulation of which present many difficulties.

Development of Multizone Reservoirs

We should not think of the planning of the drilling program for an oil-producing property as a procedure involving only surface arrangements; it is a three-dimensional problem. We must think in terms of footages to be drilled, the depth of penetration of the wells and the subsurface arrangements that determine the formational interval or intervals from which they will produce. Some fields contain great thicknesses of producing formation, seldom uniformly saturated. Often, continuous bodies of impermeable rock separate two or more well-defined zones of production and water-bearing intervals may intervene between oil-bearing strata. In such cases, we must decide for each well the depth to be attained, the interval or intervals that will be left open for production, the arrangement of casings, packers, cement plugs and other devices necessary to exclude water, control production and prevent admixture of fluids from different horizons.[2,4,6,11]

With an accurate log available for study of a representative series of wells in an area, inspection will generally suggest a convenient grouping of the oil-yielding strata into one or more producing intervals. A continuous body of shale or other impermeable material should separate producing intervals. The presence of an intermediate water-bearing formation will require application of appropriate water-exclusion procedure and zoning of the upper and lower oil-yielding strata into different producing intervals. If marked differences in formation pressure, gas-oil ratio, water "cut" or gravity of the oil are noted in different zones intersected by a well, it will probably be advisable to adopt a penetration and casing program that will permit of producing from each separately. If possible, all the operators in each field should reach a general agreement upon the producing intervals to be separately maintained, and the casing and water-exclusion program necessary to accomplish it. A uniform program is advisable to prevent possible intercommunication of fluids from zone to zone through differently cased wells. This is

particularly important in the vicinity of actively encroaching edge water which might develop troublesome water incursion in edge wells, to the detriment of continued production from other oil-yielding strata in the same producing interval.*

Drilling Separate Wells to Each Zone.—In earlier years it was considered impractical to complete and operate a well to produce from more than one zone simultaneously. If conditions required development of more than one zone at a time, separate sets of wells were drilled to each zone. This system of exploitation is expensive from the standpoint of footage drilled but permits of a maximum rate of production and early realization on oil and gas values. Maximum efficiency in oil recovery is probably obtainable by this plan of development.

If more leisurely development is permissible, a less expensive method is that of producing from each zone in turn with one set of wells, deepening the wells from zone to zone progressively as upper horizons become depleted. This plan is practical only when fields are operated cooperatively or under "unit" control. It has been used in many fields though it possesses an inherent disadvantage in that there is always a tendency to deepen wells to lower, more prolific horizons before upper zones are fully depleted. Each deepening operation may require setting a smaller size of casing, and hole diameters in the lower zones are likely to be too small for efficient production unless costly, large-diameter casings are used in the shallower horizons.

An alternate plan involves drilling wells initially through the full depth of the producing formation, draining the deepest zone first, and then exploiting shallower zones progressively by plugging back and perforating the casing to take production from an upper zone as the underlying zone becomes depleted. This method permits of systematic drainage through casings of uniform diameter, and the plugging and perforating can be done cheaply and quickly. However, this method requires large initial capital outlay in drilling and casing wells to maximum depth before receiving any revenue.

Equipping Wells to Produce from Two or More Zones Simultaneously.—If there are no marked differences in formation pressure, permeability, gas-oil ratio and quality of the oil in different zones and if a well is remote from edge water, there will perhaps be no objection to perforating the casing so that production may be secured from two or more zones at once. Fluids from all zones enter the well simultaneously and flow together to the surface. No effort is made to keep separate the production from different zones and there is no opportunity for exercising selective control in regulating production from different zones. This practice is common in many California fields where very thick multizone deposits are found. Variations in formation pressure and extent of depletion in different zones restrict the producing interval that may be included in any one well. In some fields, where thick, lenticular formations are productive and where the barren interstratified shale bodies are of uncertain continuity, operators have entered into penetration agreements designed to limit the intervals from which wells may take production during certain time periods.

Methods of well completion and operation have also been devised and successfully applied, in which fluid from each of two or more zones is produced separately and simultaneously through the same well. By placing cement plugs or packers about the casing between zones, fluid from different zones may be kept separate and the rates of production regulated by special types of control valves. Such installations,

* Uren, L. C., Development of Multi-zone Reservoirs, *Petroleum Engr.*, February, 1944, pp. 82–87.

although seemingly complex, have nevertheless proved entirely feasible in numerous installations and have many advantages. Multizone wells permit important economies in reduced drilling costs, saving in casing and tubing, drilling equipment, derricks, flow and gathering lines, pumping equipment, roads and other facilities. However, they do not afford as satisfactory control of production and are likely to have somewhat lower drainage efficiency than single-zone wells.

Determining the Most Advantageous Well Diameter

One of the important decisions that the engineer engaged in oil-field development will be called upon to make is that of determining the most advantageous well bore and diameter of casing to be employed. The problem has both physical and economic aspects. Large-diameter wells permit of more efficient operation and usually can be drilled with greater assurance of satisfactory completion. The casings necessary to support the large-diameter hole, however, are much more expensive than casings that may be employed in small-diameter wells, and a balance must be sought between these opposing factors.

Though the practical and theoretical advantages of the large-diameter hole, from the standpoint of drilling and production efficiency, have long been recognized, there has nevertheless been a notable trend toward "slim-hole" drilling that has been dictated primarily by considerations of economy fostered by proration restrictions. Some believe that slim-hole programs may find wide application; others, that they may be advisable only under special circumstances. Perhaps no program will be correct under all conditions that may be presented. Each field presents its own peculiar problems that will require varying casing programs.*

The diameter of the well and the casing in it will influence the cost and efficiency of operations during both the drilling of the well and its subsequent period of production. Small-diameter holes can be cased less expensively, and under favorable conditions the cost of drilling may be less for the small hole and it may be drilled more rapidly. This is not necessarily true, however, and where drilling conditions are difficult, the larger diameter hole may be drilled less expensively and more rapidly. Where intricate equipment must be manipulated in the well during the course of drilling, as in coring, fishing and certain types of cementing operations, large-diameter wells are advantageous. In the subsequent period of production, the large-diameter well is preferable from every point of view. It develops superior productive capacity and greater ultimate recovery; it produces with lower gas-oil ratio, therefore more efficiently from the energy-consumption standpoint. The economy of small-diameter casing and the high production efficiency

* Uren, L. C., Determination of the Most Advantageous Well Diameter, *Petroleum Engr.*, April, 1944, pp. 119–122.

of the large-diameter well may be combined by drilling a small-diameter hole down to the cap rock and then reaming to a larger size through the reservoir rock and by gravel-packing a perforated liner of small size in the enlarged portion of the well.[1,3,12]

For a given set of conditions, there is an optimum size of well and well-casing diameter that will be found most advantageous. However, this is not necessarily the smallest practical working diameter. Current drilling practice restricts finishing diameters of wells to a minimum size in which a 4¾-in. liner is placed in a hole at least 6 in. in diameter, to a maximum of 8⅝-in. casing in a 10½-in. hole, which may be reamed through the reservoir rock to as much as 20 in. and gravel-packed. The problem is largely an economic one, and the operator must balance any possible economy in drilling and casing the smaller diameter well against its greater maintenance and operating cost and lower production efficiency. Proration practices have a controlling influence under some conditions.

Development of Surface Plant and Equipment

The drilling of wells constitutes only one phase of the general problem of oil-field development. In addition, the operator must give attention to the building of roads to facilitate transportation of materials and equipment, and power and water development and distribution must also be considered. The provision of a gathering and storage system is essential, and the erection of buildings to house shops, reserve supplies, power plant, office staff and equipment, sleeping and dining facilities for the employees, living accommodations for their families and other camp necessities will be important considerations in the early development period.

Transportation of supplies and equipment will necessarily receive early consideration, for timber, rig irons and parts, drilling equipment and casing must be hauled to the sites selected for the wells. Ordinarily, motor trucks will be used in transporting supplies and equipment, so the roads constructed must be capable of withstanding heavy loads and the grades should not be excessive. Routes should be selected that will give convenient access to all parts of the property.

Unless the property is near a town where ordinary living accommodations are available for employees, camp facilities must be provided in advance of other development work. Such facilities may not at once be developed to the same degree as may be necessary or desirable during later years, but the initial effort in this direction must be adequate to provide the necessary camp conveniences. Machine and forge shops adequately equipped to care for such repair work and tool dressing as will be necessary must be provided in advance of development work;

and a warehouse and office building to house the clerical and technical staffs must be built. These facilities may be of rough temporary construction, with the expectation of replacing or improving them later if results of development warrant it, but if it is certain that the property will be productive over a considerable period of years, it will be more economical to build at the outset for the estimated productive life of the property.

The provision of power will be an important matter. This requires, first of all, selection of the form of power, which may be either steam, electric or internal-combustion engine power. If steam power is determined upon, it will be important to develop a source of water suitable for boiler purposes. This may necessitate the drilling of a water well or the construction of a dam, or it may be necessary to buy water from outside sources. Distribution of water over the property will require a piping system adequate not only for boiler purposes but to provide water for drilling needs as well. The erection of boiler plants with all incidental and related equipment at various points about the property, or of a larger central plant, will require careful designing if reasonable efficiency is to be secured. Distribution of steam from power plants to the points of use will require a system of steam mains. Electric power necessitates the installation of poles, wiring and transformers in addition to the steam plant, unless power is purchased from outside sources.

As soon as the first well is completed and placed on production, it will be necessary to provide oil storage sumps, reservoirs or tanks and gathering facilities for both oil and gas. This part of the surface equipment will ordinarily be developed gradually to keep pace with the productivity of the wells as completed, but its layout and design should be carefully planned in advance with reference to the shape and size of the property and the topography. Gas traps of suitable capacity and design must be provided to separate occluded gas from the oil. Dehydrating equipment, often a very essential part of the surface plant in the declining years of the property, is not ordinarily necessary during the early development period.

In addition to the foregoing essential features of the surface plant, many other details must receive consideration: an electric lighting system is desirable; telephonic communication with various parts of the property will be a great convenience; fire protection is important. An absorption or compression plant to strip gasoline from natural gas, or a small topping plant is often an incidental part of the oil-lease equipment.

The equipment of the property belongs distinctly to the development period. Although the surface plant must be developed more or less gradually, the property cannot be expected to operate at maximum efficiency until the surface equipment is complete and every element of it

is properly coordinated. Both the cost of the plant and the cost of development represent capital outlay that will be productive over the greater part of the life of the property, and as such they are of equal significance in planning for its development.

INFLUENCE OF PRODUCTION CONTROL ON OIL-FIELD DEVELOPMENT

Competitive methods of exploitation of oil fields have at times been responsible for production of petroleum in excess of market needs. Under competitive stimulus the activity of each producer is dominated by the necessity of taking possession of the oil within drainage influence of his wells at the earliest possible moment. Market needs are subordinated to competitive necessity, and once brought to the surface the oil must be marketed, for storage is expensive and evaporation losses are high. In this way, oil is produced in defiance of fundamental laws of economics, production only remotely responding to demand and price. The result has at times been persistent overproduction and dumping of surplus oil on an oversupplied market at prices far below the product's intrinsic worth. Overproduction results in price depression, occasionally to levels below the cost of production, and leads to general demoralization of the industry. Cheap oil leads to wasteful use and use for inferior purposes. A low-priced product cannot be so efficiently produced as a high-priced commodity. Much of the inefficiency of the present-day oil industry is chargeable to the low price which the product commands. Much oil is today left in the ground because more efficient methods of recovery are unprofitable. Operators are necessarily forced to skim the cheaply produced "flush" oil with the aid of the natural energy with which it has been endowed. Highly competitive production methods make less efficient use of the natural-gas energy stored in the oil than would be possible under more orderly and systematic methods of well control.

So seriously has overproduction influenced the welfare of the oil industry that producers have resorted to cooperative methods designed to secure some measure of production control. Though essential from the standpoint of general welfare and preservation of a remunerative market, cooperative production control, of necessity, restricts the oil producer's freedom of action in exploitation of his property. His development program may be dictated by the general industrial situation to such a degree that some of the principles set forth in the preceding sections of this chapter must be modified or even entirely disregarded.

The theory of jurisprudence which regards oil and gas as fugitive substances, belonging to whoever may be in a position to reduce them to possession, has been seriously questioned within recent years and seems to be gradually yielding to a viewpoint which regards the oil and gas

present in a geologic structure as community property. This view recognizes the right of the landowner to produce only so much of the oil and gas as may have been stored by nature within the boundaries of his property. In primary exploitation, his proprietary interest is further limited to such oil as he may be able to produce with his share of the natural energy associated with the oil and gas. The oil and gas pool in place of the individual tract of land is thus recognized as the production unit. Although this advanced theory of ownership of oil and gas resources has not as yet been written into our governing laws, it has been inferentially recognized by some of the oil- and gas-producing states in their exercise of the police power in enforcement of regulatory laws which have been upheld by the courts. This theory of oil and gas ownership has also been advanced by such authoritative bodies as the U. S. Federal Oil Conservation Board, the American Petroleum Institute and the American Bar Association.

Proration Practices in the United States

Recognition of the rights of the community as superior to the rights of the individual producer has provided the basis for a system of production control that has found wide application within the oil-producing industry during periods when oil-producing capacity exceeds market needs. In order to prevent serious overproduction, drastic price reduction and wasteful use, the practice of proration has come into vogue. Under state regulation fostered by agencies of the Federal government—or in some jurisdictions where state conservation laws do not exist, by cooperative agreement among producers—the right of each operator to produce is restricted to what is considered to be his fair share of the market outlet. In some fields, curtailment is drastic and operators are permitted to produce but a small percentage of their potential production. Gradually this method of production control has taken hold of the petroleum industry until, at times, it has dominated the outlook of the industry even to the point of determining the spacing of wells.

Confronted with this system of regulation that restricts the outlet of his property to a certain rate of production, the economic planning of the field exploitation program is in some degree taken out of the hands of the oil producer. He is compelled to pattern his field-development program to accord with the dictates of an agency beyond his individual control. This agency may be paternalistic in the sense that it insists on what is considered best for the industry as a whole, but its dictates may at times be directly at variance with the financial interests of the individual producer. The informed operator does not object to this system of production control, for it is a necessary institution, designed to secure the economic balance of a great industry. Without it, chaotic

conditions would exist precluding profits for all but a few of the more fortunate operators. The producer must strive, rather, to adapt his program to meet the requirements of the proration authorities yet secure to himself such advantages as may be possible within the framework of the governing rules.

The basis for computing proration allowances varies in different jurisdictions. The most common method has been to allow each well to produce a certain percentage of its estimated potential production. Other methods have been based in whole or in part on productive acreage owned, or on formation pressure. Depth of wells and specified minimum and maximum rates of production have been factors in some proration formulas. No one basis is productive of fair results under all circumstances, and thus administrative agencies have often been tolerant in seeking the most acceptable method of computing the allowable rates of production, permitting one basis in some fields and another in others.

Where potential production of the individual well is the basis for computing the proration allotment, an operator seeking to increase the market outlet for his property is encouraged to drill additional wells. If the system of proration provides that each well may produce the same percentage of its potential, irrespective of the number of wells or their spacing, the operator with closely spaced wells gains an unfair advantage over his neighbors who, perhaps, have been more conservative in planning their spacing program. Overdrilling, encouraged by this system of proration, has resulted in excessive development costs in some fields. In many instances, the assigned quotas can be produced with but a small percentage of the wells actually drilled. Thus, economic waste has resulted. As additional wells are drilled, beyond what are needed to produce the field quota, the allowable production for the individual well must necessarily be reduced. Gradually, the per-well allowable is diminished until the individual well may not produce enough to pay out in a reasonable time. The entire enterprise may thus become uneconomic: yet with fewer wells, a very profitable result might be attained.

Unit Exploitation of Oil Pools

Many of the disadvantages of competitive exploitation may be avoided and production control greatly facilitated by the adoption of a plan of operation in which all landowners in each field agree to pool their interests in a single operating organization or to conduct their operations in accordance with a general plan upon which the majority agree. The individual pool or field thereby becomes the production unit, as is desirable from the standpoint of recovery efficiency; and, yet, associations of

operators in different pools may still compete with each other for their share of the market demand.

Advantages of Unit Exploitation of Oil Fields.—Very definite advantages and economies accrue to the oil producers in any field through unitization of development and producing operations in comparison with what is possible by competitive exploitation. Unit operation permits of more systematic and orderly development and leads directly to more efficient recovery of the available oil and gas. Through group control of oil-producing properties, a superior gas-pressure control, more uniform well spacing and better coordination of drilling programs are possible. More efficient production methods and concerted effort to exclude water will inevitably lead to increase in the percentage recovery. This represents direct conservation of natural resources and should appeal not only to the oil producer but also to the consuming public and to the government, which is interested in securing an adequate supply of petroleum as a guarantee of national security in time of war. Probably more can be accomplished through conservation of this character than by any other means. It may be possible to double or even triple our reserves through the use of more efficient methods of extraction which group-exploitation methods would make possible. In addition to actual physical wastage of oil, which the competitive system of production entails, the economic losses resulting from unnecessary duplication of plant and personnel, overdrilling and generally higher production costs incidental to small-scale operations also have an important bearing on conservation of oil and gas resources.

The Trend toward the Unit Plan.—Nearly all students of petroleum-industry economics now agree on the desirability of unitization of the oil-producing industry in the United States, but as yet there is no general agreement on the means by which it is to be accomplished. Many plans have been proposed, most of which present certain difficulties, some of a legal character, some economic. Some present an attractive picture from the academic point of view but are unsuccessful in application because they fail to recognize the vagaries and prejudices of human nature. Unitization by any plan involves a surrendering of certain rights which, under the competitive system, the independent operator now enjoys. Many oil producers have lacked sufficient confidence in their competitors willingly to surrender these rights and view with suspicion a program which would admittedly involve very radical changes in existing relationships. They have failed to recognize the great advantages that would accrue and compensate for such sacrifices; nevertheless, a gradual change in sentiment within the industry has been apparent. In earlier years, there were few who were willing to accept the "unit plan." More recently, most of the recognized leaders of the industry have expressed themselves as favorable toward it and it has received the endorsement of the Federal Oil Conservation Board, the American Petroleum Institute and the Mid-Continent Oil & Gas Association. A committee of the American Bar Association has recommended it as the only plan offering permanent relief from the irrational and uneconomic situation with which the industry has had to contend.

Unitization of the oil-producing industry is at once a remedy for the vexing problem of overproduction, a means of conserving and efficiently utilizing what remains of an invaluable and irreplaceable natural resource, and of reducing the unit production cost of American petroleum so that it may compete to better advantage in world markets with cheap flush oil produced abroad. It will assure the producer of a more stable price structure and greater ultimate profit than is possible under the competitive system. These are statements that can be proved to the satisfaction of any reasonable

businessman, and in the main they are accepted by the majority of oil producers; it but remains to find the most acceptable way of bringing about the desired change. Some believe that the producers in various fields can be induced voluntarily to pool their properties or at least to enter into agreements to conduct their operations in accordance with a common plan. Others, who have observed the difficulty with which such agreements are secured, believe that coercive measures are necessary and are recommending legislation that would make it possible for a majority of the operators in each productive field to determine upon a program by which all must abide. In case of opposition from minority interests, the police power of the state would be invoked to make the majority program effective.

Possible Methods of Accomplishing Unitization of Oil Pools under Competitive Conditions.—It is interesting to compare some of the plans that have been proposed for bringing about unitization of the oil-producing industry. They range from simple cooperative agreements among neighboring producers to elaborate systems of legal enforcement in which the Federal or state governments are to be given power to compel and enforce operation of fields as units. We may conveniently classify the various proposals into two groups: (1) those which assume voluntary agreements as the basis for unitization and (2) those assuming some degree of Federal or state enforcement.

Unitization by Voluntary Cooperation of Producers.—Considering first the voluntary cooperative plans, varying degrees of unitization are possible, ranging all the way from simple offset and spacing agreements to complete merging of properties and interests in a single operating organization. If the producer recognizes the advantages and accepts the principle of unitization, he should be prepared to go all the way, for only by complete unitization are the maximum benefits of the plan realized. Often, however, this is difficult of attainment owing to conflicting interests and lack of agreement on comparative values of different tracts. In most cases where efforts toward voluntary cooperative unitization have been made, an unwilling or unreasonable minority has defeated its consummation. When this method must be depended upon, a compromise plan falling somewhat short of complete unitization must generally be accepted.

Cooperative Agreements with Divided Interests.—Usually it will be easier to negotiate a cooperative agreement among a small group of producers than among a larger group. There have been many instances in which a number of operators have agreed to exploit their properties according to an agreed plan to their mutual advantage. One of the best examples of this form of unitization is found in the Dominguez field of California, where two large companies owning most of the productive area have developed the field in accordance with a common spacing and penetration program, have agreed to maintain uniform pressure conditions in the productive wells and cooperatively injected surplus gas into wells on the crest of the structure in an effort to maintain field pressure. As a result of this cooperative work, a materially greater recovery is indicated than if the usual competitive methods were followed.

Complete Unitization with Undivided Interests.—Generally it will be easier to achieve complete unitization in advance of development activity than at a later date when irregularity in the extent of development and real or fancied differences in value of the various tracts will complicate the problem. In a prospective field yet to be tested by the drill, land titles will generally be divided among several or perhaps many different owners. Instead of owners retaining title to their individual tracts they may agree to pool their interests, each accepting in lieu of his specific title an undivided interest in the entire acreage, proportional to the ratio of his acreage to the total acreage. Each owner then contributes in the same proportion to a fund for drilling one or more test wells and such other development and exploration expense as may be necessary.

One difficulty experienced in carrying out this plan is that of determining how much acreage should be included in the unit. Where this consideration is of importance, it may be provided that each tract (say, each 40 acres) must be tested and proved by the drilling of a productive well before being admitted to the unit; or, if admitted in the preliminary organization, that the owners may receive no revenue until their tracts are proved to be oil bearing.

Control of the enterprise may be placed in a new trustee company formed for the purpose, in the stock of which the several owners share in proportion to their acreage; or, by agreement, one of the group may be authorized to conduct the development and exploitation of the entire property under the scrutiny of an executive committee representative of all of the owners. The royalty owners should be included in the organization if the greatest advantages of the plan are to be realized, but it is possible to proceed without their cooperation by giving due attention to the securing of equitable drainage of the different tracts. The necessity for doing this, however, defeats in part, the fundamental advantages of the unit plan. The right to develop and operate their individual tracts may be reserved to the members under general unitization rules laid down by the executive committee, but this is less desirable than the alternative plan of entrusting exploitation of all properties to a single organization, for only by this means may maximum efficiency and minimum unit production cost be realized. Unitization with undivided interests has been approved by the Mid-Continent Oil & Gas Association, and rules for the guidance of members in entering into unitization agreements have been formulated and adopted.[48]

An interesting example of successful unitization through the pooling of prospective acreage and retention of undivided interests is found in action taken by operators in the Van field, Van Zandt County, Tex. Here 5,800 acres of prospective productive territory, owned by six different companies, have been pooled and an operating agreement worked out whereby one of the six is developing and operating the tract as a unit under the general supervision of an operating committee composed of one representative of each of the member companies. The cost of development and exploitation was prorated among the member companies on an acreage basis, and profits were distributed on the same basis for the first 2½ years. Then an independent engineering appraisal of the properties was made and a new operating agreement drawn up in which the values instead of the acreage of the different tracts became the basis for assessment of expenses and distribution of profits. Provision was also made for revaluation of the properties after another 2½ years had elapsed, with readjustment of values set up in the first appraisal. An unusually thorough geological and geophysical survey of the field made in advance of any development work provided the basis for determination of prospective acreage to be included in the unit.

Another plan, appropriate for use in unproved areas, is the "community lease." Here a promoter seeks to secure the advantages of unit exploitation by inducing all landowners in a prospective area to lease their acreage to a single operator. Allocation of royalties among the lessors is in this case on an acreage basis rather than a production basis. Such a lease was consummated by the Union Oil Company of California in connection with the operations of this company on the Wellington dome in Colorado. In another instance, at Belvedere Gardens, in the Los Angeles basin of southern California four community leases were negotiated by one company in a townsite area from 2,000 separate landowners.

A more difficult situation is presented when it is proposed to unitize properties in a field that has already embarked on its productive career. Here the various tracts are normally found in different stages of development, field pressures depleted in varying degrees; different spacing and development programs have been followed and the physical condition and equipment of the plant and wells will vary widely on

different properties. It would be obviously unfair to base the relative interests of the property owners on acreage contributed to the unit without regard to relative values of different tracts, and when we come to fix relative values that would be acceptable to all concerned, we are confronted with a rather difficult problem. Yet, it would seem to be a reasonable procedure for all owners to agree to entrust the appraisal of the properties to a group of disinterested engineers and abide by the result. The appraisal should be based on an estimate of what the properties would be worth under competitive conditions rather than on what they will actually yield under unit operation.

Once appraisals acceptable to all concerned have been prepared, we may proceed with the unitization program along either of several lines. If the owners wish to retain technical ownership of their individual properties, it may be arranged that each tract shall be assigned for a period of years to a trusteeship to be operated in the common interest, all expenses and profits being distributed pro rata among the members in accordance with the initial valuation of the properties. A better plan is that in which the individual operators, both lessees and royalty owners, exchange titles to their holdings for stock in a new company organized as a holding company to take charge of and operate the properties as a unit. Such a plan offers the maximum advantage from the unitization standpoint. If all producers and royalty owners in a producing area will but agree to accept appraisals of their properties by a group of disinterested and competent engineers, there would seem to be no particular difficulty in carrying through a unitization program on the latter basis. If control of production is a matter of importance to individual owners, it might be provided that each owner may claim his percentage of the oil produced in lieu of a monetary profit from its sale. If some of the properties are not sufficiently developed to permit of a satisfactory appraisal of their present-day value, the early adjustments of percentage ownership in the unit may be tentative and subject to revision at a later date when a more precise appraisal is possible. A part of the capital stock and dividends may be held in reserve for a time to permit of making appropriate readjustments in the original tentative appraisals.

One of the outstanding examples of successful unitization of a major field during the early development stage is found in the Kettleman Hills North Dome field of California. This field has an estimated productive area of upward of 16,000 acres, nearly half of which is owned in fee by the Standard Oil Co. of Calif., while 15 other companies control nearly all of the remainder. After the productive area of the field had been fairly well delineated by 10 producing wells and the partial completion of more than 20 others, a unitization agreement was effected whereby the group of 15 companies referred to pooled their acreage and vested full control and operation in the Kettleman Hills North Dome Association. A cooperative agreement was also reached between the association and the Standard Oil Co. of Calif., whereby a total of 20,260 acres of prospective oil-producing land is to be operated as a unit. A large part of the acreage, other than that owned by the Standard Oil Co. of Calif., is government land, leased under the provisions of the Mineral Land Leasing Law, and officials of the U. S. Department of the Interior took an active part in promoting unitization of the field. Each member company of the association contributes to the expense of development and shares in the profits in proportion to the acreage owned. Provision is made for gradually eliminating such acreage as may be found nonproductive. Owners of acreage without the area originally thought to be productive may be admitted to the association on proving the productivity of their land by drilling test wells. The association has not acquired actual ownership of the properties of the member companies but is granted exclusive possession and operating rights thereon. The officers of the association have full authority to determine the

development program and methods of well control and operation. Drilling and producing operations on association acreage are in charge of a single field organization.

Perhaps the simplest method of securing unit operation in the case of a group of producing properties is that of a single producer purchasing the property of all of the others. There have, of course, been many instances in which operators have purchased neighboring properties for the purpose of consolidating acreage and securing more economic operating conditions. The Cabin Creek field in West Virginia has been cited by the Federal Oil Conservation Board as an outstanding example of the advantages of single ownership. The entire field was, in this case, acquired by a single company and has been exploited in accordance with scientific and economic principles with special attention given to well spacing and control of field pressures. As a result, controlled production in accordance with market needs has been attained and the rate of decline of the wells has been much more moderate than in other fields of the region.

In a number of instances, efforts at unitization have been made in fields where production had declined to such a point that repressuring or other secondary methods of exploitation were necessary to continue economic operation. Secondary exploitation methods do not adapt themselves well to the competitive system, and operators are generally more willing to enter into a cooperative plan when their properties have reached this stage than in earlier years when they might have considered it more advantageous to retain individual ownership and operate on a competitive basis. A notable example of unit promotion for the purpose of repressuring is found in the Delaware Extension pool, Nowata County, Okla., where properties aggregating 4,140 acres with 629 producing wells were consolidated and placed under a single management. In this case a new company was formed to which previous owners assigned their properties in return for a stock interest in the whole. The basis for distribution of stock was the daily production at the time of consolidation. An arbitrary value per barrel was placed on all production, and relative values were set on natural gasoline production, royalty interests and surface ownership. Surface equipment was purchased at an agreed price. It was unfortunately found to be impossible to pool the royalty interests in this field; hence the maximum advantages of unitization were not realized. The results have nevertheless been eminently successful in that important increases in the rate of production and economies in assembling and operation of equipment have been achieved. Pressure control on the producing wells, impossible under competitive conditions, played an important role in assuring success of the repressuring operations. By unitization this group of properties has been rehabilitated and is in a position to produce at a profit for many years to come.

Compulsory Unitization.—Although it is advantageous from every point of view for the individual producer to pool his property with others in a unit operation, practically it is often difficult to secure the consent of all of the operators and royalty owners to do so. If a few tracts, or even a single strategically situated property is withheld from the unit, it may defeat the unitization plan. This situation has so frequently developed that many who have had experience in efforts to promote units are skeptical of the general success of the voluntary cooperative method and are urging legislation as a means of compelling unitization. Varying degrees of compulsion have been suggested by different writers, ranging all the way from national legislation designed to force complete unitization in every field to milder forms in which a state may have authority to enforce cooperation only to the extent that a majority of the operators in each field may elect.

The Federal Oil Conservation Board and a committee representative of the American Bar Association have expressed the opinion that the Federal government is without authority in legislating on this matter, but both agree that it is within the province

of the individual oil-producing states to do so. The American Bar Association committee concluded that state or national legislation designed to compel operators tc merge their properties in an operating unit would be unconstitutional, but that under the police power of the states it would be legal to compel a reluctant minority to enter into a cooperative agreement to operate their properties in accordance with whatever plan of exploitation the majority might elect. The committee went so far as to frame a bill embodying this principle for submission to the several state legislatures.

Restriction of Oil Production by Gas-conservation Laws

Some measure of control of oil production by state authorities is possible through exercise of the right of the state to prevent waste of natural resources. In many flush fields it has been found necessary to produce a certain quantity of gas with each barrel of oil brought to the surface, and the volume of gas so produced has often been in excess of field and market requirements so that much surplus gas has been released to the atmosphere. The state governments have in some cases legislated against wastage of this character, requiring operators to restrict flow of their wells to produce no more gas than may be put to economic use. This has necessarily operated also to restrict oil production; indeed, the gas conservation laws have in some cases been framed and administered primarily as a means of restricting the rate of oil production from flush fields. The California Gas-conservation Law affords a good example of this. The California law declares it to be unlawful to permit waste of natural gas into the atmosphere and gives the State Oil and Gas Supervisor authority to fix reasonable gas-oil ratios in productive areas where gas wastage occurs. He may also approve and enforce operating programs designed to permit gas injection in partly developed oil fields. Strictly enforced, this law would have a powerful tendency to encourage cooperative exploitation and unitization of oil fields.

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CHAPTER IV

DRILLING EQUIPMENT AND METHODS: GENERAL FEATURES

CLASSIFICATION OF DRILLING METHODS

The methods used in drilling oil wells may be classified into two groups each utilizing fundamentally different systems of excavation and radically different types of equipment. These are called "churn drilling methods" and "rotary drilling methods." We may further classify the various systems of drilling and types of rigs under these two general headings, as follows:

I. Churn drilling methods:
  1. Cable drilling systems:
     a. Primitive rigs utilizing "spring poles" actuated by man or animal power.
     b. The American "standard" rig.
     c. Various portable and semiportable rigs.
  2. Rod and pole drilling systems:
     a. The Canadian pole-tool rig.
     b. The Galician rod-tool rig.
     c. Various types of "free-fall" rigs.

II. Rotary drilling methods:
  1. Hydraulic rotary systems:
     a. Rigs utilizing mechanical feed control.
     b. Rigs utilizing hydraulic feed control.
     c. The diamond drilling rig.

In addition to this primary classification, we might appropriately establish a third group in which features of both the churn and rotary drilling methods are employed. This group may be called

III. Combination drilling methods:
  1. "Combination" rigs capable of employing either cable or rotary methods as conditions may require.
  2. The standard-circulating system of drilling, utilizing churn drilling tools and a system of removing cuttings commonly employed in connection with the rotary drilling systems.

Some of the systems of drilling mentioned in the above classification are now almost obsolete in oil-field practice; in fact, only two of them are extensively used at the present time: the hydraulic rotary system and the American standard cable system. The scope of this volume does not permit of a detailed explanation of all the different systems and types

of rigs classified, and we shall therefore devote the available space to a description of the more modern drilling methods and equipment now extensively employed in oil-field work. The present chapter will be concerned with matters of general interest that relate to all methods of drilling. Chapter V will be devoted to a more detailed discussion of churn drilling methods, with particular reference to the American standard cable system, while Chaps. VII to X will describe modern rotary drilling rigs and methods. The reader is referred to the bibliography given at the close of this chapter for descriptions of the rod-tool and free-fall drilling systems which have been used chiefly in the Russian, Rumanian and Galician fields.

GENERAL REQUIREMENTS OF DRILLING METHODS

Any successful system of drilling oil wells must provide, first of all, a means of fracturing or abrading the rocky formations that must be penetrated to reach the oil reservoir; and, second, it must provide a means of excavating the loosened material from the well as drilling proceeds. In addition, provision must be made for preventing the walls of the well from caving and for sealing off water and gas. Wells are usually intended to be vertical or nearly so. The well must, of course, be deep enough to reach the oil reservoir, and it should be of adequate cross section to permit of the introduction and operation of a pumping device of sufficient capacity to make operation of the well profitable.

Oil wells vary in diameter within wide limits. Prospect wells, drilled primarily for information rather than for production, may be finished with a diameter as small as 2 or 3 in. Wells in the Russian and Rumanian fields have in earlier years been drilled with initial diameters as great as 36 in. It is usually necessary to decrease the diameter of a well progressively as the depth increases, in order to provide adequate clearance for the drilling tools and to permit of the introduction of metal casings for retaining the walls and excluding water. In American practice, initial diameters commonly range from 10 to 27 in., depending upon the depth to be attained, the number of reductions in diameter necessary and the size with which it is considered desirable to finish the well. This latter factor depends, in turn, upon the productivity of the territory. For American practice, finishing diameters range from 3 to 10 in., most operators preferring a free working diameter of at least 4 or 5 in. The 2-in. plunger pump, which is the smallest size ordinarily used, requires a free working space at least 3 in. in diameter. The 3-in. plunger pump, a commonly used size, requires a free working diameter of about 4½ in. In addition to these working clearances, there must be some space about the pump in which oil can accumulate.

The maximum depth to which it would be practical to drill a well

with modern equipment and methods would depend somewhat upon the character of the formations to be penetrated, the size and weight of the equipment used, the power available and the skill of the driller. Wells have been drilled with churn-drilling cable tools to depths in excess of 9,000 ft. and with rotary tools to more than 16,600 ft. There seems to be no good reason why drilling equipment of either type could not be designed to drill to greater depths if necessary.

The depth to which it is profitable to drill is the determining factor in most drilling operations. This economic limit of depth varies with the quality of the oil, the prevailing selling price, the productivity of the well, the cost of drilling and other factors. Such factors are quite variable. Within recent years, wells drilled to depths in excess of 12,000 ft. have been profitable in some fields where the oil is of high grade and the production rates have been large and well sustained.

HISTORICAL DEVELOPMENT OF THE ART OF DRILLING

The place and time wherein the first wells were drilled are unrecorded in history, but it is known that the Chinese were among the first to make industrial use of wells drilled by mechanical methods. It is said that prior to A.D. 1700 the Chinese had sunk over 10,000 wells to depths of more than 500 m. for the production of brine.[33] The early Chinese well drillers made use of cable-tool, churn drilling methods and practically all of the equipment used—the rope, casing and derrick—was made of wood, the elastic bamboo being widely employed. The power used was man power. The drilling tools were suspended from the end of a spring pole, the churning movement being given to the tools by the workmen running up a short incline and jumping down, one after another, on a small platform attached to the spring pole. The primitive methods and equipment developed by the Chinese more than two centuries ago may still be observed in drilling operations in interior China, where salt produced by the evaporation of brine pumped from wells is an important article of commerce.

The spring-pole method, with minor variations in the manner of applying the power, has also been widely used in other parts of the world in drilling wells for various purposes, chiefly for brine. The records of well drilling in the United States began in 1806, when the first American well was drilled near Charleston, W. Va., for brine. The appliances used in drilling this first American well were very simple. A spring pole 20 ft. long was mounted on a forked stick of wood and fastened to the ground at one end. Attached to the free end of this spring pole, was the drilling cable, to the lower end of which the iron bit, $2\frac{1}{2}$ in. in diameter and quite primitive in construction, was fastened. Stirrups, also attached to the free end of the pole, were used by two or three men in producing the

necessary churning motion, their weight pulling the cable down, while the elasticity of the pole served to jerk it back with sufficient force to raise the tools a few inches. The casing consisted of two long strips of wood, shaped into half tubes and wrapped with twine. The conductor was a straight, well-formed, hollow sycamore gum, 4 in. in internal diameter, sunk to bedrock in a shallow pit. Even in this primitive equipment, used on our first American well, all the essential features of what we now call the "standard" cable system of drilling were present. We still use the same method of drilling, but our equipment is more elaborate.

The first well drilled for oil in the United States was the Drake well, sunk near Titusville, Pa., in 1859. Many of the shallow wells that were drilled in the same locality following the discovery of oil in the Drake well were drilled with the aid of spring poles by hand methods. As might be expected, the early operators of these laborious and slow hand-drilling rigs soon began to contrive mechanical means for applying power. The steam engine was the best known prime mover in the early days, and naturally the first mechanically driven drilling rigs were operated by steam engines. The engines used were of the simplest type: an ordinary reversible engine, with the piston controlled by a plain slide valve—a type of engine which in spite of its inefficiency is widely used even today for the drilling of oil wells. The engine was used to give a reciprocating motion to the drilling cable through the instrumentality of a large wheel, called a "band wheel," the metal shaft of which was connected to one end of a walking beam by means of a crank and pitman. The drilling cable attached to the opposite end of the walking beam was thus given a churning motion with each revolution of the band wheel.

The first rigs were light and small, for the wells were shallow and the duty not severe. For hoisting out the tools a simple tripod was used, made of three sticks of timber tied together at the top and supporting a crude wooden or iron pulley. The drilling cable was passed over the pulley and power applied to the free end by a hand-power windlass or a mechanically operated hoisting drum. Such drilling rigs served well enough in the shallow territories which were first exploited for oil but were soon found to be inadequate when deeper drilling became necessary or when more difficult conditions were encountered. Small changes were made here, an improvement there. New parts were added as new duties were imposed, until finally there was evolved the modern cable-drilling rig which we call the "American standard rig."

Eighty years of development, during which hundreds of thousands of wells have been drilled by this method, have now fairly well standardized the equipment used. However, there is some variation in the size and weight of the parts of the rig to adapt it to the conditions imposed in different fields. Deeper drilling, characteristic of the Western American

fields, has also been responsible for the addition of certain new parts, particularly for the handling of heavy strings of casing.

The rotary system of drilling is of comparatively recent origin in comparison with the churn drilling methods. The first recorded use of rotary methods in drilling for oil was in 1901 in the Spindle Top field, near Beaumont, Tex. The formations overlying the oil zone in this field consist of unconsolidated sands and shales that cave seriously when subjected to the vibrations of churn-drilling tools. Its successful use in this field soon led to the use of rotary equipment in other fields, notably in California, where somewhat similar conditions were encountered. For many years it was thought that the hydraulic rotary system was applicable only in fields where relatively soft formations were to be penetrated, but during more recent years the development of hard-rock bits for use with the rotary equipment has extended its field of usefulness, until at the present time there is scarcely any type of rock ordinarily encountered in penetrating oil-producing formations that cannot be satisfactorily drilled by the rotary method.

Both the cable-tool system and the rotary system of drilling are now extensively used in the American oil fields. Each has its place; each its own set of conditions under which it is more advantageous than the other. Their relative advantages and disadvantages are to be discussed in a later section. Most of the more than 300,000 producing wells in the United States have been drilled with cable tools, but the greater annual footage during recent years has been drilled by rotary methods.

GENERAL FEATURES OF THE PRINCIPAL DRILLING SYSTEMS

In order to impress upon the mind of the reader the principal features of each of the more commonly used systems of drilling, as a basis for comparison, brief descriptions of them are offered at this point, though detailed discussion of equipment and methods of operation and control is reserved for later chapters.

THE AMERICAN STANDARD CABLE SYSTEM

The standard cable drilling rig is housed and supported by a structure which has two principal parts: (1) the derrick, a high pyramidal framed structure, erected directly over the site selected for the well; (2) a long, narrow and comparatively low structure which houses the engine or motor, the belt, a large band wheel and other mechanism provided for applying and controlling the power. These structures rest on suitable foundations of heavy timber, which together with certain other supports for the wheels and other moving parts are known as the "rig timbers." Substantial flooring is provided under the derrick and within the engine-house and belt house, and a platform is built at one side of the belt house

on the same level as the derrick and enginehouse flooring and connecting the two (see Figs. 24 and 25).

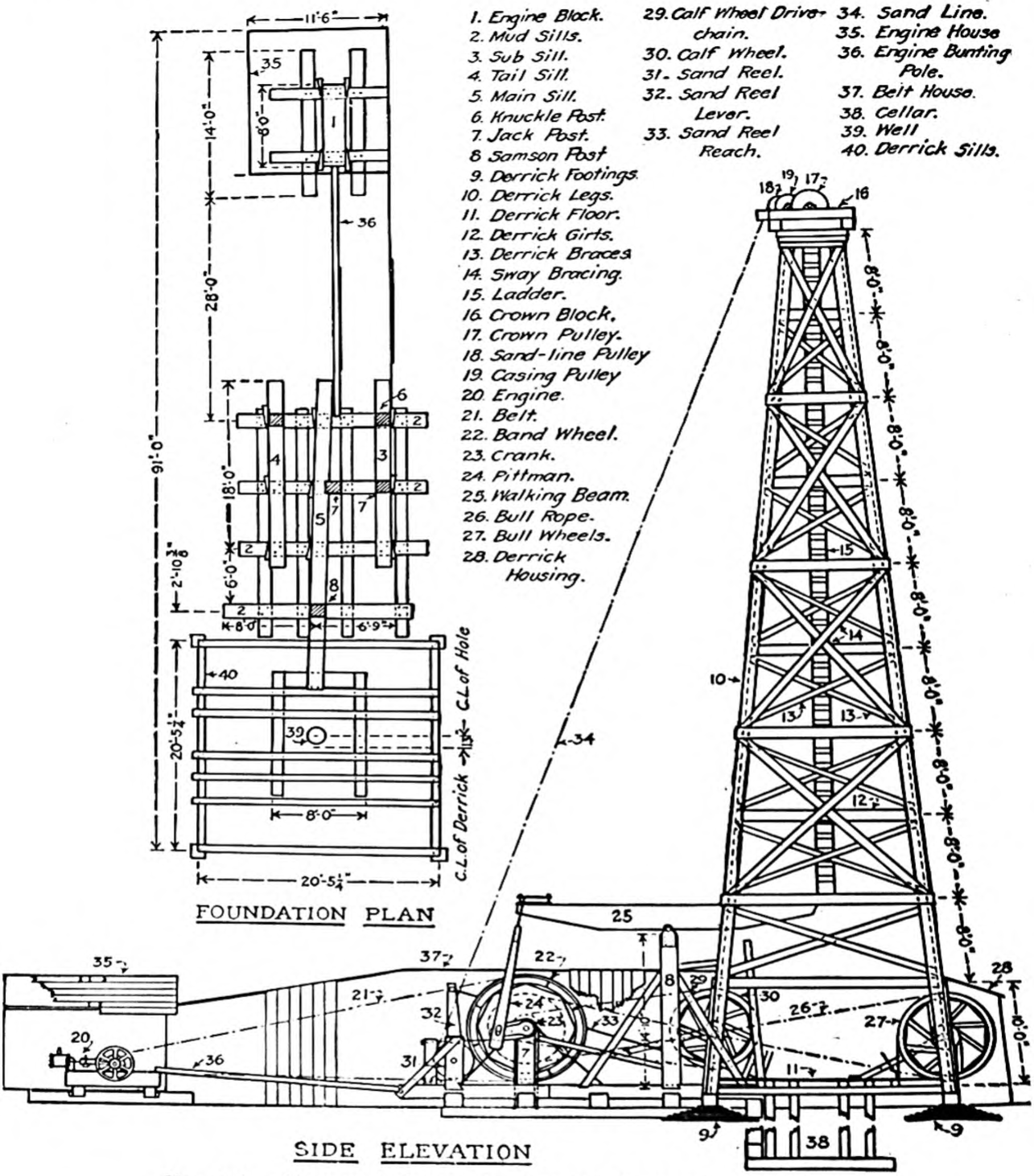


FIG. 24.—Plan and elevation of an 82-ft. standard cable rig.

Motive power is transferred from the engine pulley to a large wooden band wheel by means of a belt. The band wheel is mounted, by means of metal gudgeons, on a steel shaft resting in metal bearings supported on two substantial "jack posts." Overhanging the bearing on one end of the band-wheel shaft, a crank is keyed; this may be connected by

means of a metal wrist pin to the lower end of a pitman, the upper end of which is attached by a metal stirrup to the end of a "walking beam." The walking beam is a long substantial timber, supported at its center on a shaft and bearing, which permit it to oscillate as the crank revolves. The end of the beam opposite that to which the pitman is attached overhangs the well, and the drilling cable on which the drilling bit is suspended may be attached to the beam with an adjustable temper screw. By means of this simple mechanism the bit is raised and lowered an amount

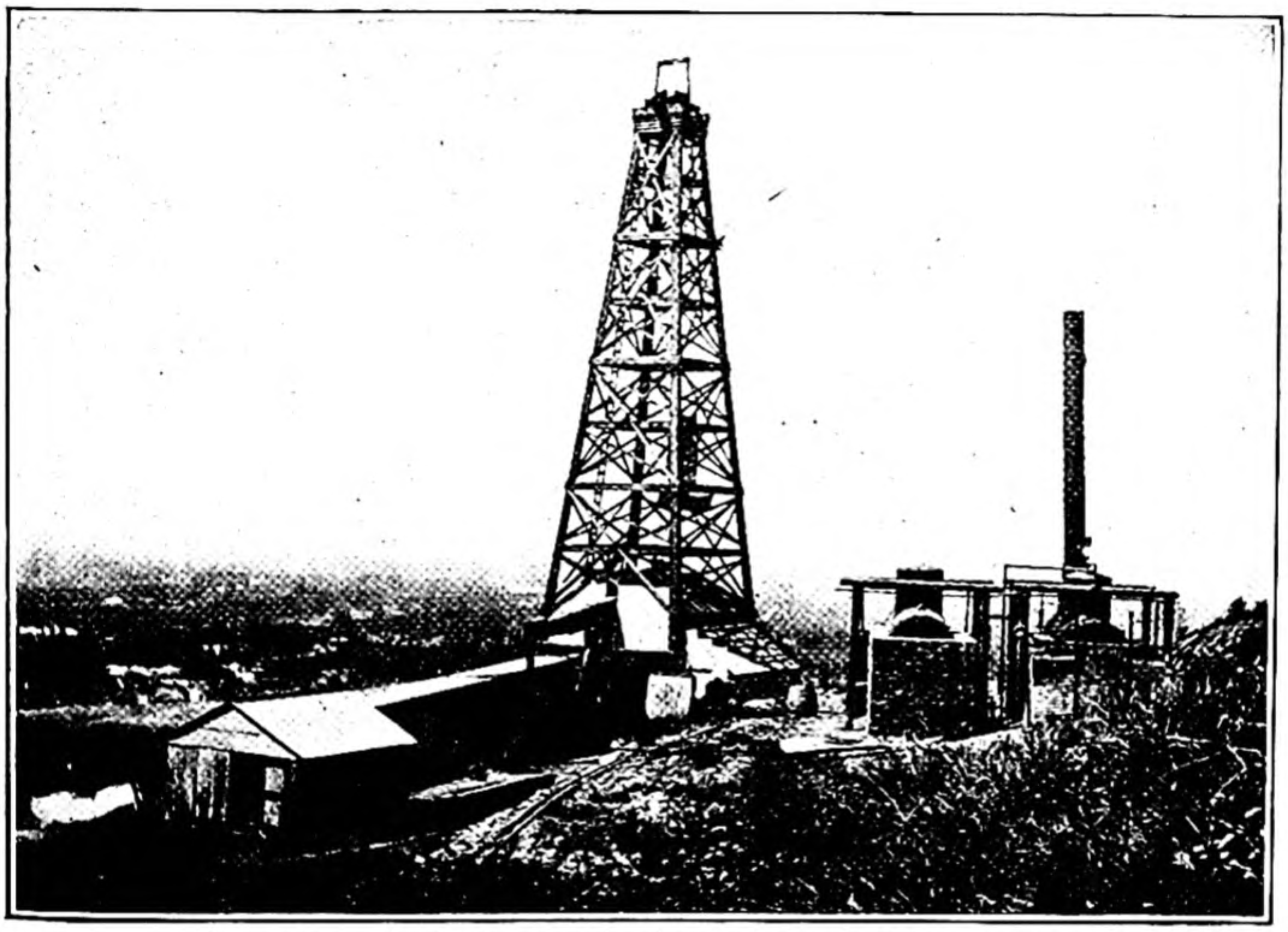


Fig. 25.—An 82-ft. standard cable rig, California type.

governed by the "swing" of the walking beam with each revolution of the band wheel. The "stroke" of the beam is adjustable by changing the position of the wrist pin in the crank. Six holes are provided in the crank for this purpose, each at a different distance from the center of rotation of the band-wheel shaft. With 6-in. rig irons, the movement at the end of the beam ranges from 24 to 74 in., each successive hole in the crank adding 10 in. to the sweep of the beam.

On the side of the band wheel a wooden tug pulley is mounted, which provides a means of operating an endless rope drive (the "bull rope") to a large pair of wheels called "bull wheels." These wheels are mounted on opposite ends of a wooden or metal shaft on which the drilling cable is wound, the free end of the drilling cable passing up through the derrick to a metal sheave on the derrick "crown" and thence vertically downward to the drilling tools in the well. The bull wheels are used for applying the power in hoisting the drilling tools out of the well. A band

brake bearing on the face of one of the two bull wheels serves to control the descent of the tools when they are being lowered into the well and to hold them suspended when necessary.

On the opposite end of the band-wheel shaft from that on which the crank is attached, there is mounted a sprocket wheel controlled by a clutch. An endless chain from this sprocket drives another large wheel called the "calf wheel," on the shaft of which the "calf line" is wound. This is a substantial cable, usually of steel, which passes up through the derrick to the crown and is threaded back and forth between four stationary sheaves ("crown block") and three traveling sheaves mounted in a massive frame to which the "dead line" or end of the cable is also fastened. This "hoisting block," as it is called, is used in lowering, lifting and supporting the heavy strings of casing suspended in the well. A large hook and special pipe clamps, called "casing elevators," provide a means of suspending the casing from the hoisting block. A band brake on the rim of the calf wheel serves to control the descent of the casing, or to hold it suspended when the calf-wheel clutch is disengaged.

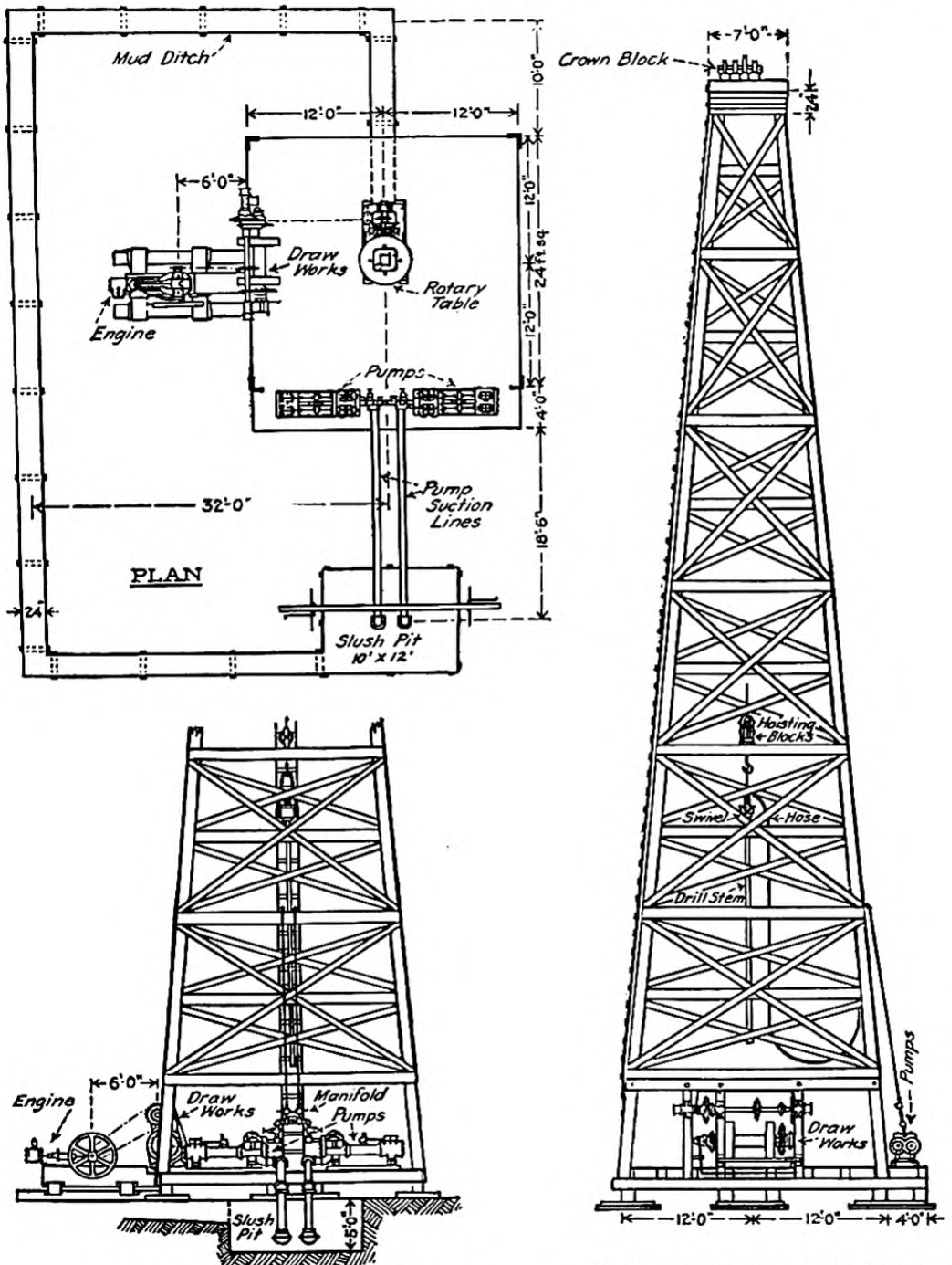
The "bailer," by means of which the material loosened by the drill is removed from the well, is suspended on a light steel cable or "sand line," which passes over a sheave at the crown of the derrick and thence downward, outside of the derrick, to the "sand reel," a small metal drum mounted on a horizontal steel shaft. The sand reel and its shaft and bearings are mounted on a movable cradle which permits of a friction pulley keyed to the same shaft being brought to bear against the face of the band wheel, thus revolving the sand reel, "spooling" the sand line and raising the bailer. The bailer is lowered by gravity, a post brake on the sand-reel friction pulley serving to control the speed.

It will be observed that the mechanism described in the foregoing paragraphs has four chief functions: (1) to churn the drilling tools up and down in the well, thus accomplishing abrasion of the material in the bottom; (2) to lower the drilling tools into the well and hoist them out by unwinding or winding the drilling cable on the bull-wheel shaft; (3) to raise, lower and support the heavy metal casing with the aid of the calf line, or casing line, and calf wheel; and (4) to hoist and lower the bailer, used in excavating the material loosened by the drill. In addition to the main features of the rig outlined above, there must be the necessary brakes and levers for controlling the engine and the various wheels and a great variety of tools and implements useful in conducting the work. These will be considered in greater detail in Chap. V.

General Features of the Rotary System

In the rotary system of drilling (see Figs. 26 and 27), the rock mass through which the well is drilled is abraded and chipped away by the

downward pressure and cutting and grinding action of a revolving steel bit which may assume various forms. The cutting bit is revolved by a substantial steel pipe or "drill stem," extending from the top of the



(Redrawn, with additions, from illustration in National Supply Co.'s catalogue.)

FIG. 26.—Plan and elevations of a rotary rig.

drilling tool, to which it is screwed, to a point some distance above the derrick floor. At the level of the derrick floor the drill stem passes through a gripping device in a power-driven rotary table mounted over the mouth of the well. The form of the gripping device is such that,

while the table has a positive grip on the drill stem, the latter is free to move vertically through the table even while it rotates.

To the top of the column of pipe comprising the drill stem a massive swivel is attached, which provides a means of suspending the stem in the well, allowing it to rotate with the table, while the upper part of the swivel, the hoisting block and supporting cables remain stationary. The drill stem and swivel are hollow so that water or mud can be pumped

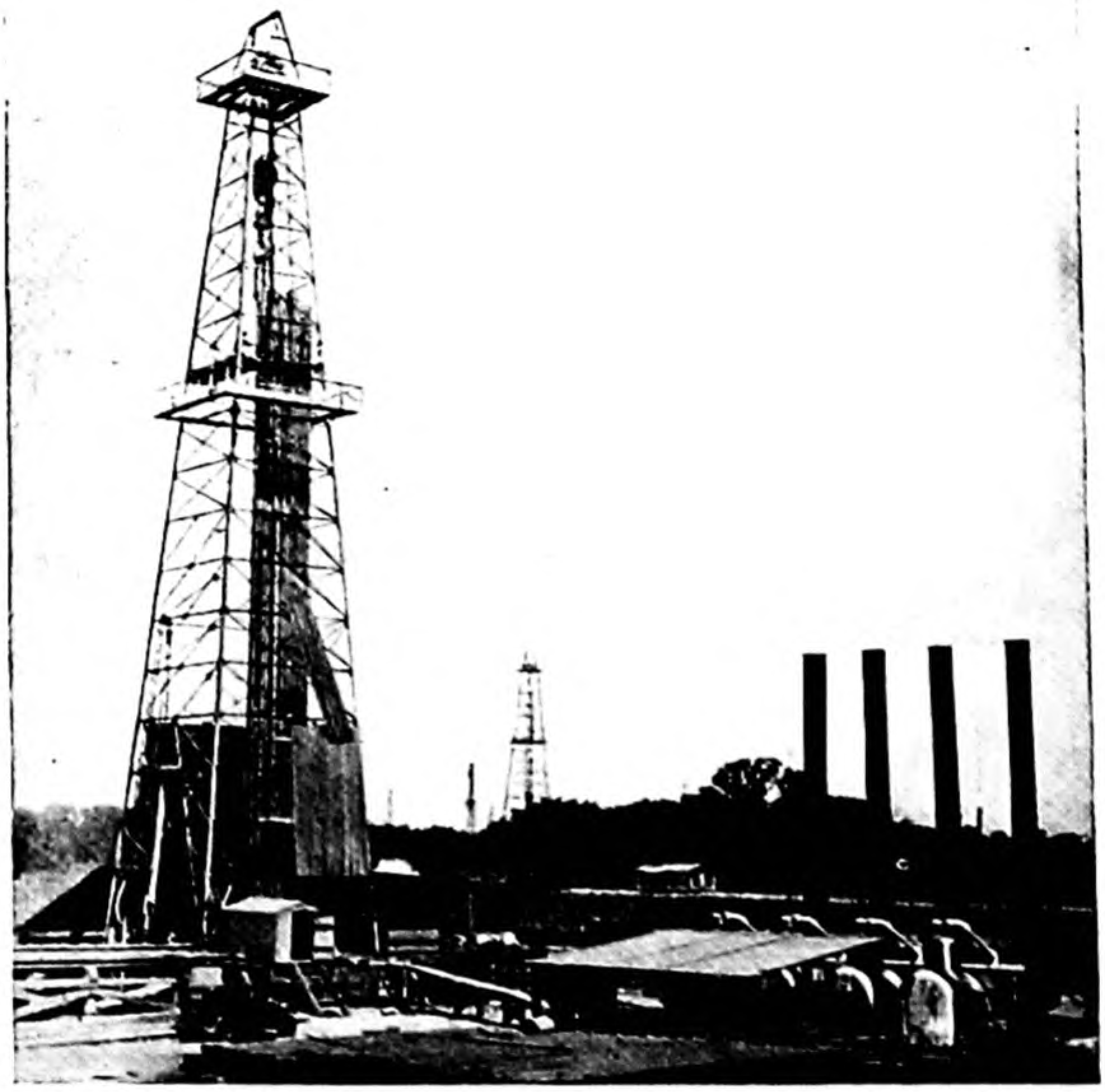


FIG. 27.—A 122-ft. rotary rig in the Oklahoma City field, Okla.

down through the stem to the drilling bit and out into the well through holes in the bit. This fluid sweeps under the bit, picks up the rocky material loosened thereby and carries it to the surface through the annular space between the drill stem and the walls of the well. This circulation of fluid through the well is maintained by the pressure of either of two powerful pumps connecting through a flexible connection to the swivel on top of the drill stem. Fluid from the well overflows into a mud ditch or wooden trough through which it moves sluggishly, allowing the coarse cuttings from the well to settle. The fluid, thus freed of the coarse gritty material, and containing only fine-grained clay in suspension, flows into the sluch pit, from which it is picked up by the pump suction for further circulation through the well. The mud fluid,

thus used repeatedly in closed circuit, need be replenished only to the extent that it is absorbed by the porous formations penetrated by the well.

The swivel, drill stem and bit may be raised or lowered in the well by means of a steel cable operating through a massive hoisting block strung from sheaves at the derrick crown. The free end of this cable passes down through the derrick and is wound on a heavy hoisting drum supported by metal bearings mounted in a substantial steel frame. The hoisting drum is driven from a line shaft by chain belts and sprockets, with individual clutches so arranged as to provide two or more speeds. The line shaft is usually driven by a chain belt from a sprocket on the crankshaft of a steam engine, though a variable-speed electric motor or an internal-combustion engine can be adapted to the work through the use of intermediate gearing. Heavy band brakes on the flanges of the hoisting drum permit of suspending the weight of the drill stem and swivel when the power clutches are disengaged. On the line shaft there is also a sprocket for a chain drive, which operates the rotary table. The latter connects either directly with the jackshaft of the rotary table or indirectly through an intermediate drive shaft. The drive shaft may also support an additional sprocket for operating a mechanical mud mixer, and two catheads useful in applying power to the heavy pipe tongs used in tightening the joints of the drill stem and for other purposes. The hoisting drum with its supporting shaft, the drive shaft, sprockets, brakes, clutches and supports are known collectively as the "draw works," commonly furnished as a unit by manufacturers specializing in rotary drilling equipment.

The size and weight of the equipment used vary according to the diameter and depth of the hole to be drilled. Preference as between light and heavy equipment also varies in different fields. For example, the rotary equipment used in Texas and Louisiana is often lighter than that used in California.

The rotary derrick is a higher and heavier structure than the derricks described in the previous section for cable drilling but is otherwise similar in form and design. The height is often 122 or 136 ft. The space enclosed within the four legs is often 24 ft. square at the level of the derrick floor and 5½ ft. square at the crown. The legs are reinforced with "doublers" for the full height and, if the well to be drilled is a deep one, sway bracing is applied on the outside of each panel between alternate girts. The engine housing is but little more than a low lean-to structure or an extension of the housing at one side of the derrick. There is, of course, no occasion for the belt house and plant walk described in connection with the standard cable rig.

A platform of 2-in. plank is built across one side of the derrick at one or more elevations to provide the necessary footing for the derrick

man in manipulating the upper ends of the stands of drill pipe as they are made up or "broken out." Such platforms are frequently extended outside of the derrick, and railings are built around the outer edge for greater security of the derrick man in moving from one side of the derrick to the other. The square space on top of the derrick about the crown block is similarly enclosed as a protection to one engaged in inspecting or oiling the sheaves or in stringing the hoisting cable over them. Such platforms and hand railings are required by law in some states as an accident preventive. Reinforcement of the derrick floor across the side where the sections of stem are placed on end when not in the well, and suitable timber braces and guides to keep them in position in the upper portion of the derrick are also important considerations.

A shallow cellar is excavated beneath the derrick, in which a vertical conductor pipe of riveted steel, corrugated pipe, or wood staves is placed and carefully plumbed and braced. A rectangular hole is cut or is left in the center of the derrick floor, of the same size and shape as the metal base of the rotary table, a timber frame to which the table is bolted resting directly upon the derrick center sills. The latter, in turn, are supported on substantial posts resting on concrete piers or timber footings.

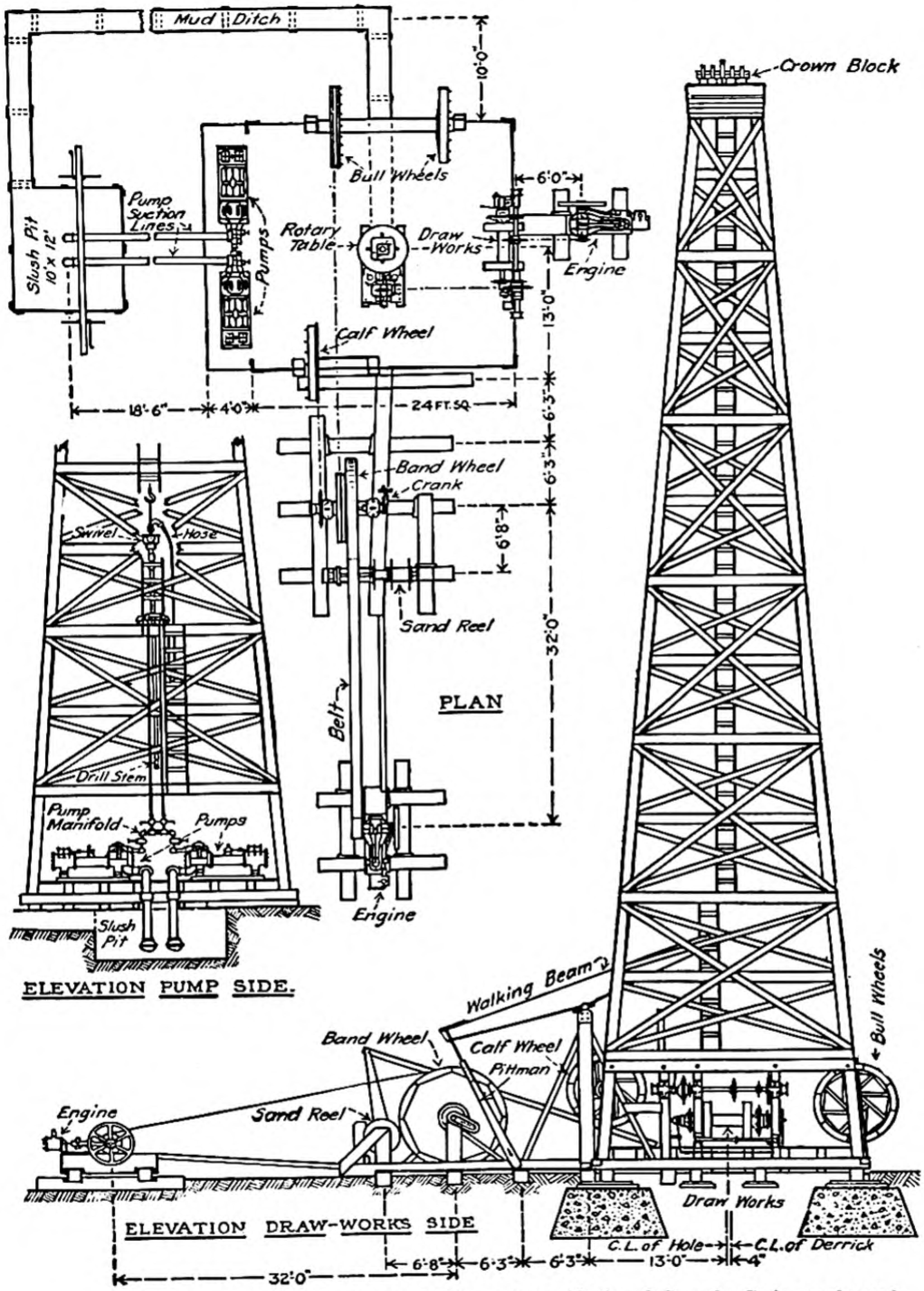
A slush pit of adequate capacity is excavated at one side of the derrick, conveniently placed for the pump suction lines. A wooden trough 24 in. wide and 12 in. deep, at least 125 ft. long and graded to a slight slope, is constructed about two or three sides of the derrick at or slightly above the ground level. It is arranged at one end to receive the overflow of fluid from the well and at the other end to discharge into the slush pit (see Fig. 26). A supply of clay of suitable character is hauled from the nearest available source and piled ready for use at one side of the slush pit.

Combination Rigs and Methods

With a view toward securing the best features of both the rotary and cable-tool methods of drilling, many operators prefer what is called a "combination rig," which includes all the essential equipment pertaining to each of the two methods under one derrick. The rotary equipment is then used when it seems best adapted to the conditions to be met, and, when the cable tools are preferable, they will be rigged and made promptly available. In some combination rigs, the rotary and cable tools are arranged to work simultaneously.

The usual form and arrangement of the combination rig are illustrated in Fig. 28. It will be noted that there is no change in the position of any of the parts of either the rotary or cable-tool equipment. The cable tools can readily be operated through the opening in the rotary table, using the slips in the latter instead of a casing block. However, it is a

simple matter to move the rotary table out of the way temporarily, if necessary. One end of the hoisting cable may be attached to the hoisting



(Redrawn, with additions, from National Supply Co.'s catalogue.)

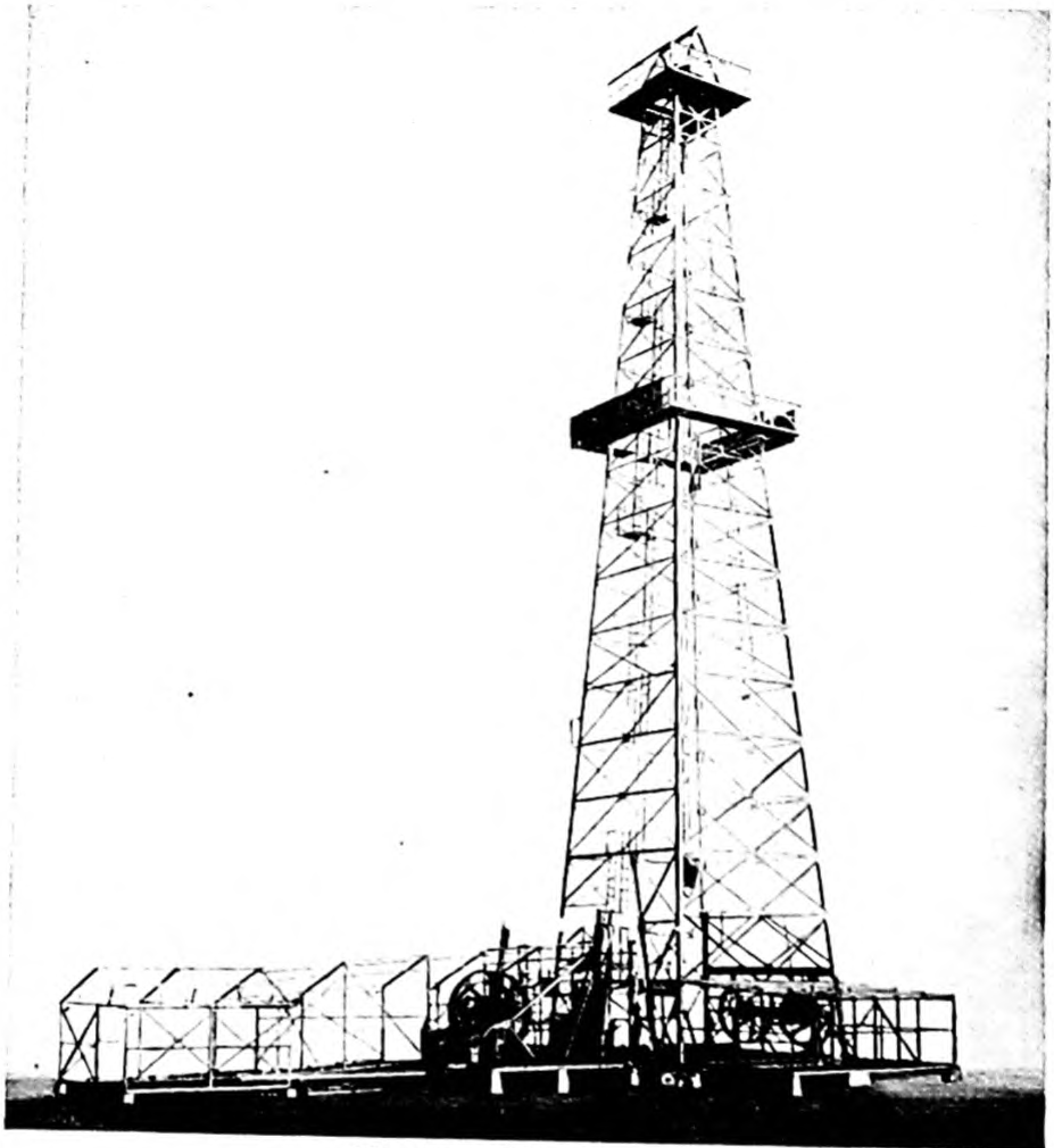
FIG. 28.—Plan and elevations of California-type combination rig.

NOTE: One or more platforms with railings (not shown in drawing) are ordinarily provided around the outside of a California derrick for the safety and convenience of the derrick man. The crown block is also customarily surrounded by a suitable platform and railing (see Fig. 31).

drum of the draw works, and the other to the calf-wheel shaft, so that the hoisting blocks may be raised or lowered from either end. The calf wheel is more powerful than the hoisting drum because of its greater

diameter and slower movement and is therefore preferred in handling casing.

The derrick used is often 122 by 24 ft., this size being used more than any other in deep rotary drilling. The requirements imposed by the rotary equipment determine the size and weight of the combination



(*Courtesy of Emsco Derrick and Equipment Co.*)
FIG. 29.—Typical 122-ft. California-type combination rig.

rig, a rig heavy enough for rotary drilling having ample strength for any strain imposed in cable drilling. However, it is customary to use a heavy derrick with ample bracing. Certain slight changes in the arrangement and number of the sheaves in the crown block are necessary.

Other arrangements of the equipment in a combination rig have been suggested and applied. One design places the draw works under the walking beam near the samson post, driving the draw works by a chain from a sprocket on the band-wheel shaft. In this case one engine may be used and the calf wheel may be dispensed with, using the hoisting drum of the draw works to manipulate the casing when either system of drilling is employed. Occasionally the samson post is pivoted so that the walking beam may be swung to one side out of the way of the rotary drill stem and swivel.

Comparative Advantages and Disadvantages of Rotary and Cable Systems of Drilling

On investigating the relative advantages and disadvantages of the two principal methods of drilling, we find that each has its own particular sphere of usefulness. Conditions in each individual field will determine which is best adapted. For the comparatively shallow fields of the Appalachian region of the United States, where the formations to be penetrated consist chiefly of hard, slaty shales and well-indurated sandstones, the cable tools have been and are almost exclusively used. The cable-tool method is also preferred by most operators in certain of the Rocky Mountain and west Texas fields where the oil sands lie at shallow depths and where hard formations must be penetrated. On the other hand, recent drilling in most of the California, Mid-Continent and Gulf Coast fields of the United States has been almost exclusively by the rotary method. Particularly is this true where great thicknesses of soft, semiconsolidated formations must be penetrated.

During the earlier years of rotary drilling there was considerable distrust of this method, and numerous arguments were advanced against its use chiefly by drillers trained in the use of cable tools who naturally disliked a process differing so radically from that which had been used since the early days of the industry. The rotary method was originally thought to be applicable chiefly to certain peculiar conditions prevalent in the fields in which it was first successfully applied, but, as its use was extended to other fields and the records attained by it became known, the rotary was eventually accepted as a real competitor of the older method. Indeed, within recent years, wherever deep drilling has been necessary, the rotary has been the preferred method, and in many of our recently discovered fields it has been used exclusively. Improvement in design and the development of hard-rock rotary bits have been largely responsible for this rapid trend toward the use of the rotary method.

When the two methods are impartially compared, it is at once evident that the rotary has certain definite advantages that make it preferable under ordinary conditions. It is more rapid, and because of this it operates at a lower cost per foot and secures production within a shorter space of time. By its use, strings of large-diameter pipe may be carried to great depths with minimum loss of working diameter and at a considerable saving in the cost of casing. It has been found possible to drill through great thicknesses of unconsolidated formations with the rotary under conditions that are practically prohibitive for the cable tools. It is simpler—much of the technic that required years of experience for the cable driller to acquire is unnecessary in rotary drilling. To be sure, successful operation of the rotary equipment requires a technic of its

own, but it will be generally admitted that it is easier to acquire the art of rotary drilling than to become a skilled cable driller. The rotary operates fairly continuously, without interruption for bailing and with a fewer number and a smaller variety of fishing jobs. Use of the circulating fluid provides a means of controlling high gas and water pressures often encountered in drilling for oil and makes possible the carrying of open hole to great depths so that the well does not have to be cased until the particular size of hole being drilled is completed. Furthermore, there is greater freedom of the casing in the well, and the landing depths and water shut-offs can be more definitely planned and the work carried forward with greater certainty of completion according to predetermined schedules. Action of the cable tools is severe, often fracturing the walls so that they cave readily. The hole drilled by the rotary, on the other hand, is clean-cut, with a minimum of fracturing of the walls, and the hole is necessarily always round so that the casing passes freely through.

Although there is much to be said in favor of the rotary method of drilling, there are some disadvantages that favor the cable method under certain conditions. Probably the greatest disadvantage that can be urged against the use of the rotary is the difficulty encountered in determining the character of the formations penetrated. It is essential that accurate data be secured for the well log, and in many cases the drilling returns brought to the surface in the sludge with the rotary equipment are so finely pulverized and contaminated with mud that they cannot be definitely classified. The color of the sludge, the presence or absence of sand and grit, effect of the formation on the bit and the manner in which the drill stem, table and mud pump behave are about all that the driller has to work on in securing data for the log. With the sandstones and harder rocks it is possible to secure a fairly good sample which can be washed free of mud from the mud ditch, but the presence or absence of argillaceous material in the formation can only be surmised since it is usually so finely ground that it is inseparable from the circulating fluid when it reaches the surface. With the cable tools, on the other hand, it is possible to get a fairly definite idea of the nature of the rock in which the drill is operating by an examination of the material brought up by the bailer, and often large fragments of the material will be found adhering to the bailer or to the drilling bit when it is withdrawn. The disadvantage of the rotary in this respect has been largely offset during recent years by the more general use of rotary core-drilling devices which give the driller an actual sample of the material in the bottom as it occurs in place and by the electrical and other methods of instrumental logging which indicate the nature of the formations penetrated by the well and their fluid content.

Another disadvantage frequently urged against the use of the rotary

is that the circulating fluid used tends to seal off the sands encountered, commercial oil sands being sometimes mudded off so effectively that the operator drills through them without becoming aware of the presence of oil. This is a particularly serious criticism in the drilling of pioneer wells in a new field, or wherever the exact depth of the oil sands to be encountered is uncertain. Even in partly developed fields where the position of the productive sands is definitely known, the oil sands exposed in the well are frequently so clogged with mud that the well never attains normal productivity. Many irregularities in the productions of adjacent wells can be explained on this basis. Such difficulty, however, is largely due to unskillful drilling, or failure to wash out the clay or condition properly the drilling fluid used during completion of the well, and is therefore not a logical argument against the use of the rotary method. It is also claimed by some proponents of the cable method that, if the oil sand is under low gas pressure, considerable water may be permitted to enter from the well, partly flooding the sand and reducing its normal productivity. It seems probable, however, that the mudding action of the circulating fluid would prevent any great quantity of fluid from entering the oil sand; furthermore, it should be readily drained from the area about the well by a few days of production after the well is completed.

Although many drillers will question this statement, it is probable that rotary holes are more frequently crooked than wells drilled by cable methods. However, crooked holes may be largely eliminated by more careful drilling methods, particularly by the use of lower bit pressures.

Unless hard-rock bits are available, the rotary makes very slow progress in hard sandstones and limestones. The fishtail bit is rapidly dulled in such rocks, and much time is lost in withdrawing and replacing the drill stem in changing bits. The cable tools may be withdrawn from a 3,000-ft. hole in 5 min., but 1 hr. or more will be necessary to remove a rotary bit. Use of the hard-rock bits will largely offset this disadvantage of the rotary, however.

The rotary equipment has a greater first cost than a cable-tool rig, and if the hole to be drilled is a shallow one, the additional cost of the rig will offset any advantage which the rotary may possess in reduction of casing expense or cheaper unit drilling cost. A standard cable rig has a much lower daily operating cost because of the fewer number of men employed, and because it requires less power; hence, unless the rotary equipment can show a marked superiority in footage drilled, its advantage from the standpoint of unit cost is lost.

Water supply and transportation are troublesome factors in some regions. Here again the standard method has the advantage, the

equipment being more readily transported and requiring considerably less water for drilling and steam-raising purposes.

Summarizing the arguments given above for and against each of the two methods of drilling, it would appear that the rotary method is superior when the oil-producing strata lie at considerable depth and their position is definitely known, when the formations to be penetrated consist mainly of soft and moderately soft rocks and when formations containing high-pressure gas are expected. The standard cable method, on the other hand, is sometimes preferred in drilling "wildcat" wells where the geologic conditions and stratigraphic sequence are uncertain and where accurate information for the well log is especially important. The cable tools are generally preferred if any great thickness of hard rock is to be penetrated, or where the productive horizons are found at shallow depths. Cable tools are sometimes used in finishing wells drilled primarily with rotary equipment, particularly if the oil sands are under low pressure, because of the danger of mudding off the productive strata by use of the latter method.

DERRICKS AND OTHER STRUCTURES FOR SUPPORTING DRILLING EQUIPMENT

All systems of drilling require the use of some type of derrick or mast to support the drilling equipment in working position and to provide some form of overhead structure from which may be suspended hoisting gear with which to lift the heavy tools and casing. Such equipment often aggregates many tons in weight and stresses of great magnitude are imposed on the supporting structures. The derrick or other supporting structure must therefore be sturdy, well braced in all directions and securely anchored on firm foundations, so that it will not collapse or be pulled over. It must be high to provide, between the sheaves at the crown and the mouth of the well at the level of the working floor, sufficient headroom in which to manipulate the long strings of tools, casing and hoisting gear.

For drilling comparatively shallow holes, a braced mast may be used in lieu of other more elaborate supporting structures. Such masts, available in various types, often designed for rapid erection and ready portability, are used on many portable and semiportable drilling rigs. For deeper drilling, a more substantial structure in the form of a derrick must be used.

A derrick is a four-sided, truncated pyramidal structure of square horizontal cross section, comprising four upright legs forming the corners of the structure, tied together by a series of horizontal girts and inclined braces. The four sides of the derrick are battered to a slope of from 1 in 5 to 1 in 12, depending upon the height and size at top and bottom. The

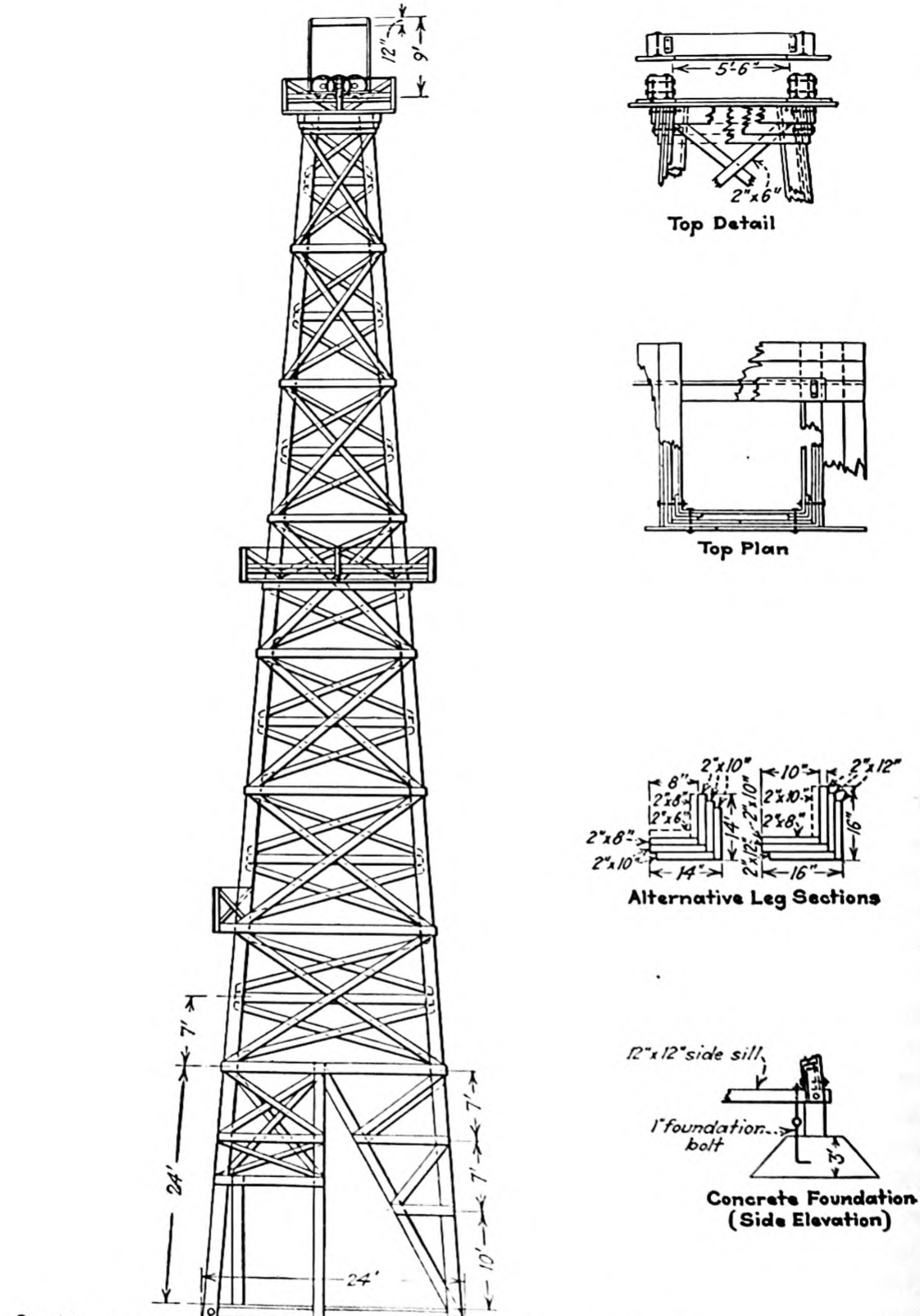
structure as a whole should possess rigidity and must not be permanently deformed when supporting the maximum load to which it will be subjected in service, or vibrate excessively under the stresses imposed by the drilling equipment when in operation. The derrick is mounted on a substructure comprising a series of sills supported on short posts, which rest in turn upon timber footings or concrete walls or piers. The working floor of the derrick, also fastened to the derrick sills, is of heavy plank. The larger and heavier items of drilling equipment rest on special supports incorporated in the substructure. Some of the drilling equipment is housed in lean-to or other separate structures of temporary character grouped about the base of the derrick.

Derrick Types and Materials

Derricks may be constructed either of wood or steel. Common pine or hemlock is generally used in the construction of wooden derricks. Harder woods, such as oak, beech or maple, are used at times in certain of the posts, sills, wheels and other members subjected to great strain or wear. Rarely, creosoted timber will be used. Steel derricks may be constructed either of the usual structural steel angles, channels, I beams, etc., or of tubular forms. For housing the lower part of the rig to protect the crew and equipment against the weather, galvanized corrugated sheet-iron or wooden sheathing may be used.

Timber Derricks.—Until rather recently, practice in the construction of timber derricks was based largely upon precendent. Little or no scientific design, in which different members are proportioned to the loads applied, entered into their construction. The National Lumber Manufacturers Association, however, has given attention to this subject, and improved designs have been developed, based on physical tests, assuring greater strength and economy in use of material.

Legs of wooden derricks are usually constructed by nailing 2-in. planks together to form a right-angled trough-shaped member. In heavy derricks each leg has often been constructed of one 2- by 10-in. plank and five 2- by 12-in. planks. However, tests have shown that a derrick leg made of one 2- by 8-in. plank and five 2- by 10-in. planks is actually stronger, though of smaller cross section (see Fig. 30). This is believed to result from a little known characteristic of wood-compression members, by which those wider in horizontal cross section than 4½ times their thickness fail in torsion rather than by direct column action. Derricks of lighter construction, appropriate only for drilling to shallow depths with cable tools, make use of considerably less timber, the cross section sometimes consisting of only two 2-in. planks. In drilling to greater depths, a second or outer pair of planks called "doublers" are frequently used to reinforce the lower part of each leg. The horizontal girts and inclined

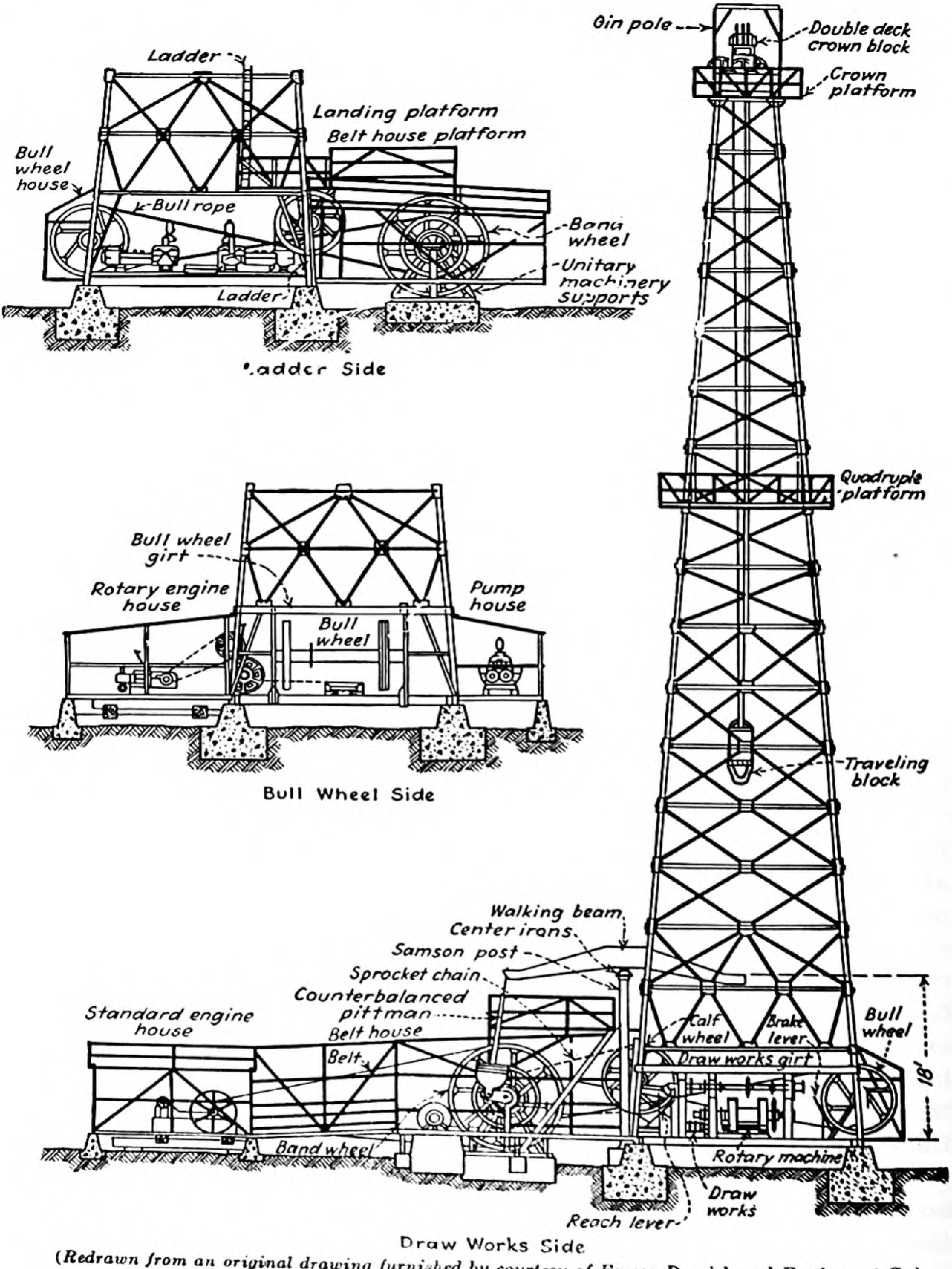


(*Courtesy of National Lumber Manufacturers Association.*)
FIG. 30.—Side elevation and structural details of a 122- by 24-ft. timber derrick.

braces are also of 2-in. material, 6, 8, 10 or 12 in. wide, depending upon the place of the member in the structure. In addition to the usual braces and girts nailed on the inside of the derrick legs, heavy timber derricks requiring additional strength are "sway braced" by adding a second set of girts on the outside of the legs opposite every alternate set of inside girts and placing long diagonal braces between the outside girts (see Fig. 28). The engine and belt house are often built of 1- by 12-in. lumber on a light timber frame, and the housing about the lower part of the derrick may also consist of light wooden sheathing. Many operators, however, prefer corrugated sheet iron for housing in the enginehouse, belt house and such part of the derrick as may require protection from the weather. For the walk connecting the derrick and enginehouse and the flooring throughout the structure, 2-in. planks are used. A rack of 6- by 8-in. timber built beside the elevated walk is provided for the support of casing, drill pipe, tubing, tools and miscellaneous equipment.

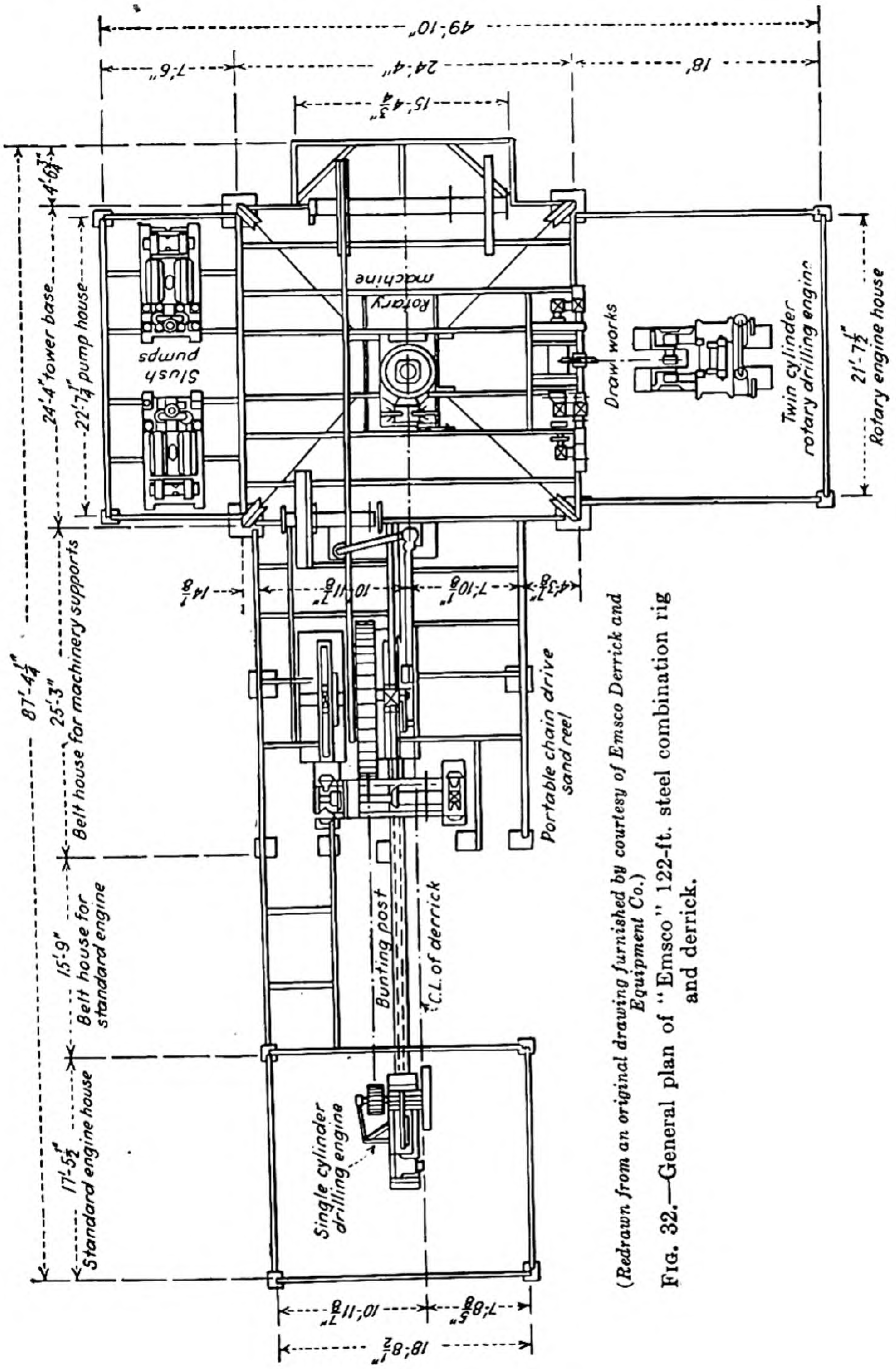
A well-constructed 122-ft. timber derrick for rotary drilling, with flooring and all necessary sills, ladders, etc., will contain about 26,000 ft.b.m. of lumber. About 30,000 ft.b.m. will be required for a 136-ft. derrick. A 74-ft. derrick, appropriate for cable drilling to moderate depths, requires about 20,500 ft.b.m. Figure 25 illustrates a typical timber derrick suitable for cable drilling. Figures 26 and 28 are illustrative of heavier and larger timber derricks appropriate for light rotary and combination rigs. Figure 30 gives structural details of an improved design for a 122-ft. timber derrick, a size that has been widely used in rotary drilling in some of the Western American fields.

Structural Steel Derricks.—For drilling deep wells with rotary tools many engineers have recently shown a preference for steel derricks. Most of these are constructed of the ordinary rolled forms, generally of mild, low-carbon steel, though occasionally of steel of higher tensile strength having higher than normal carbon content. In one popular steel derrick of this type, the legs are constructed of heavy angles, the 6- by 6- by 3/8-in. and 5- by 5- by 3/8-in. sizes being used in the larger and heavier structures, while the girts are steel angles ranging from 5 by 5 by 3/8 in. to 2½ by 2½ by 3/16 in. in size, depending upon their position in the structure. The diagonal braces are of 2- by 2-in. angles 1/8 or 3/16 in. thick. The first five panels are double diagonal braced, and struts are used to stiffen the bracing from the fifth panel to the crown. This feature is said to give the structure unusual rigidity and reduces vibration (see Figs. 31 and 32). For greater strength, structural steel derricks are reinforced with casing, set inside the angle of the legs and clamped thereto, extending from the derrick footings to the crown. One manufacturer uses 5-in. 15-lb. casing for this purpose and reports that the weight-supporting capacity of the derrick is increased 2.5 times by this



(*Redrawn from an original drawing furnished by courtesy of* **Emsco Derrick and Equipment Co.**)

FIG. 31.—"Emsco" 122-ft. steel combination rig and derrick, side elevations.



(Redrawn from an original drawing furnished by courtesy of Emsco Derrick and Equipment Co.)

FIG. 32.—General plan of "Emsco" 122-ft. steel combination rig and derrick.

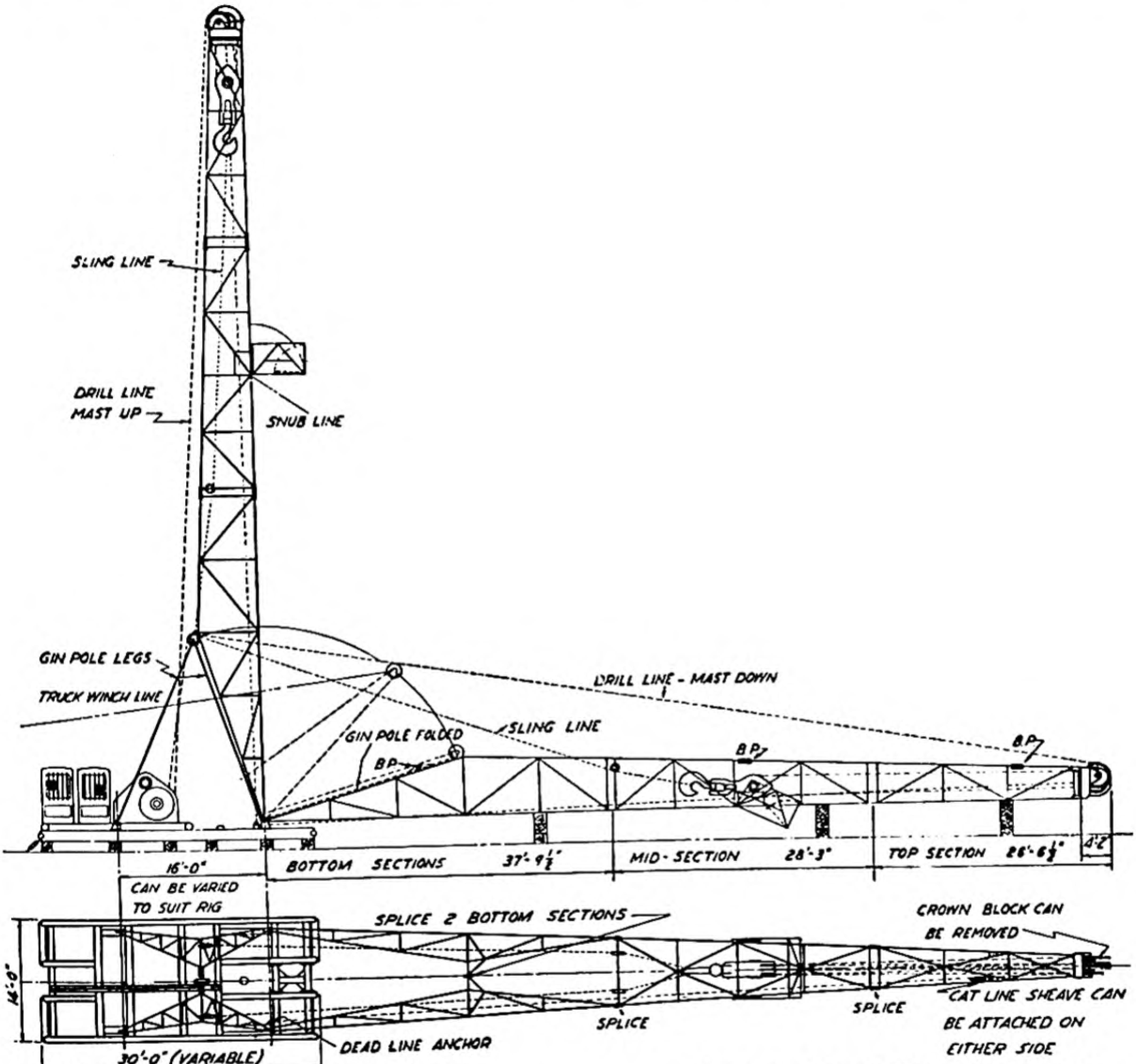
means. At two elevations in the derrick, at about 40 ft. and 72½ ft. above the floor, platforms protected with guard railings are provided for the use of the derrick man in handling pipe and equipment. The "crow's-nest" at the summit of the derrick is also surrounded by a 3-ft. railing. A steel ladderway in eight offset sections, which may be equipped with guard screens for additional safety, provides a means of ascending to any part of the structure (see Fig. 29). A 24- by 122-ft. combination rig and derrick of this type, together with steel housing, weighs about 61,000 lb.

Tubular steel derricks make use of pipe forms in all parts of the structure. This type of derrick has attained considerable popularity in some districts and is preferred by some operators to steel derricks built of structural forms. The legs of these tubular steel derricks are made of steel pipe of varying weight and size, depending upon the position of the member in the structure. Tubular derricks of duplex or triplex design have one or two pipes telescoped within the leg tubes to give additional strength. One popular make of tubular derrick provides reinforcement for the legs by an additional set of tubular members bolted to the side of each leg by specially designed clamps. Adjustable screw jacks are employed on the reinforcing members to assist in securing a uniform distribution of the load. In heavy combination rigs of the California type, one manufacturer uses either 4-in. 15-lb. or 4-in. 27-lb. pipe, and, if reinforcement is required, a 3-in. pipe, bearing its share of the load, is telescoped within the larger pipe. The girts and braces are of 2- or 2½-in. pipe. Special clamps provide a means of attaching the girts and braces to the derrick legs. For high strength, a steel of 0.40 to 0.50 per cent carbon is sometimes used. A 24- by 120-ft. combination rig of this type, including steel wheels and walking beam, may weigh as much as 83,500 lb. Ordinary heavy-duty rotary derricks of the same height weigh about 32,500 lb. Smaller and lighter tubular steel derricks, popular in many fields, are often used at operating wells. These are designed for use in occasional repair and cleaning operations but are not heavy enough or high enough for drilling operations.

Turnbuckle Rigs.—Various combinations of wood and steel in the construction of derricks have been worked out, with the primary purpose of facilitating dismantling and reassembling at a new site. One of these, which has been used to some extent in exploration work, makes use of timber legs and girts, with braces made of round steel rods. The braces are in two parts connected by substantial turnbuckles which permit of adjustment so that these members assume a large part of the strain. At the leg joints all members are bolted together through metal angle plates.

Drilling Masts

To facilitate rapid assembly of drilling equipment and moving from one well location to another, the derrick may be replaced by a braced mast of unitary construction. This may vary from a simple A-frame structure supported in working position by cables, suitable only for light



(*Courtesy of Lee C. Moore & Co., Inc.*)

FIG. 33.—Jackknife cantilever mast. Above: side elevation, showing method of erecting mast. Below: plan view, showing method of assembling mast.

service, to elaborate framed structures erected on their own supporting bases and capable of performing all the usual functions of a standard derrick in drilling wells of moderate depth. Usually the mast will be designed to facilitate disassembly or folding of component parts, small and light enough to be moved on trucks or tractors. Such masts can be moved into a new location and made ready for drilling service in but a fraction of the time necessary for erection of a standard steel derrick.

Figure 33 illustrates a type of mast widely used in rotary drilling to moderate depths. This is self-supporting, mounted on a heavy, skid-type base and is designed to be raised as a unit to its operating position with the aid of the draw works of the rotary rig. It is complete in every detail and serves every purpose served by the ordinary drilling derrick. Both the unitized base and the mast are designed so that the members fold to a size that will conform with highway clearance and weight regulations when mounted on three motor trucks. The mast is available in four sizes, the largest of which is 126 ft. high, mounted on a base 16 ft. square. This is capable of supporting 415,000 lb., or about 6,000 ft. of 3½-in. drill pipe, and permits use of the larger and heavier types of traveling blocks and hooks, and any of the conventional sizes and patterns of draw works and rotary tables may be used in conjunction with it. All necessary sheaves are in fixed positions. A steel subbase 18 by 30 ft. in size assists in elevating the mast and in providing the necessary well-head connections. The entire unit, mast and subbase, weighs about 40,000 lb. and is disassembled in eight sections.[30]

Advantages and Disadvantages of Timber and Steel as Derrick Materials

The relative advantages and disadvantages of timber and steel as derrick materials have of late been given careful attention by oil producers. The steel derrick is for a given weight stronger and more dependable under severe stress. Because of the opportunity for more accurate design in proportioning the various parts of a steel rig, this type is lighter than the wooden derrick by 25 or 30 per cent. It is claimed that the collapse of a properly erected steel derrick, even under severe working conditions, is very improbable; it may bend or buckle, but it is not easily collapsed in a manner to endanger personnel. This gives a feeling of security to those employed under it that is not always enjoyed when working under a timber derrick. Wind pressure on a timber derrick is about three times that on a steel rig, owing to the greater surface exposed by the former (compare Figs. 30 and 31). The strength of a timber derrick depends largely upon the skill and knowledge of the rig builder. Given an imperfectly fitted or nailed member, or timber of inferior quality in a vital place—and the derrick will perhaps fail under strain. Steel is more uniform in its properties, more dependable; and workmanship in a well-conducted manufacturing plant is likely to be more dependable than that to be found in rig builders "picked up" in the field. The steel structure has a longer life, if properly protected by galvanizing or by occasional painting. Wooden derricks, on the other hand, are subject to deterioration, rapid in some climates, as a result of weathering and attack of termites. From the standpoint of fire risk, the steel derrick also enjoys a considerable advantage and carries a lower insurance premium. Creosoted timber, sometimes used because of its greater resistance to decay, offers a greater fire risk than untreated timber. Again, if there is prospect of a derrick being moved from one location to another, as in exploration work, the steel derrick is much to be preferred. Overtoppling or tearing down a timber derrick with the removal of the heavy spikes used in construction is likely to cause considerable damage to the timber members, while the steel structure, being fastened together by bolts, is readily disassembled and has a high salvage value. The steel derrick affords more rigid support for the crown block, wheels and moving parts of

the equipment, with better opportunity for maintaining alignment, and consequently assuring more efficient power transmission. With proper foundations, the steel derrick permits of more uniform distribution of the load.

In considering the advantages of timber, a derrick of this material is considerably lower in initial cost than steel. Rig timber is readily available in most fields and does not have to be specially manufactured in a distant manufacturing establishment. Wooden derricks, if properly constructed of selected material on firm foundations, can be amply strong for all purposes. Owing to its greater resiliency and elasticity under strain, it is claimed that a wooden derrick acts as a shock absorber and that there is less wear and tear upon the drilling equipment than is the case with a steel derrick. Many cable drillers prefer the wooden derrick because there is less vibration; it is more flexible than steel and responds better to the churning motion of the tools. While admitting that timber derricks offer greater fire risk in a general conflagration, proponents of timber as a derrick material point out that gas is sometimes ignited by sparks resulting from rocks or metal equipment striking on the steel of the derrick, and that in the event of a serious fire no material is immune. Though timber depreciates with age, it is pointed out that wooden derricks often have a longer life than the wells that they serve.

Whatever may be the merits of the arguments set forth in the above paragraphs, it must be recorded that in spite of the greater cost, oil producers have been showing a decided preference for steel derricks in recent years, particularly in the deeper fields.

Sizes of Derricks and Selection for Different Purposes

Until 1927, there was little uniformity in the design and dimensions of derricks used in the oil fields. About this time, the American Petroleum Institute, as a phase of its standardization program, adopted standard specifications for a variety of sizes of oil-field derricks. Since the original specifications were adopted, periodic revisions have been made, but Table XIII gives the sizes recognized as standard in 1942. As a result of this effort, where formerly there were several hundred different sizes and types of steel derricks manufactured in the United States, there are now only nine that are recognized as standard.

Prior to the adoption of these standard sizes, the industry had developed the practice of maintaining certain standard sizes for the bases of derricks, generally 20, 22 or 24 ft. Derricks of different height were adapted to these bases by slight changes in the taper or slope of the sides of the structure. In deference to this earlier practice, the A.P.I. derrick standards prescribe 20-, 24- and 26-ft. base squares, and recently one having a 30-ft. square base has been adopted. Generally speaking, the size of the base square increases with the height of the derrick. The size of the opening through the "water table" at the summit of the derrick is also specified in order that crown blocks made by different manufacturers—also rigidly standardized—will fit any derrick.

Of the different sizes of derricks adopted as standard, only the four largest sizes are appropriate for rotary drilling. The 94-ft. tower is used for rotary drilling only in shallow territory. The 122-ft. derrick has been used widely for rotary drilling to moderate depths, but for deeper drilling, the 136-ft. tower is preferred. For cable drilling, most operators specify the 73- or 80-ft. structure. The 87-ft. derricks are used only for drilling unusually deep wells by the cable method. The 66-ft. derrick is primarily a "production derrick," though it may be used for cable drilling in shallow

territory. There has been limited use of higher derricks than any of these, in some cases as high as 178 ft. with a 32-ft. square base, but they have not yet been recognized in A.P.I. standards.

Selection of the size of derrick for a particular operation is governed primarily by considerations of economy in installation cost and saving of time in handling long "strings" of tools, drill pipe and casing. In deep drilling, very heavy hoisting blocks and hooks must be used, and these, being longer than the lighter equipment designed for drilling to shallower depths, require more headroom. In rotary drilling, the higher derricks permit of handling longer "stands" of drill pipe, thus expediting the work of withdrawing and inserting the drilling tools. Thus, it is estimated that a 178-ft. derrick permits of making a round trip out and into a 10,000-ft. well in 69 min. less

TABLE XIII.—AMERICAN PETROLEUM INSTITUTE STANDARD DERRICK SIZES AND DIMENSIONS
(From A.P.I. Standard No. 4, May, 1942)

Size No.*	Heights, ft.†	Base squares, ft.‡	Water-table opening§
	Steel derricks		
8	66	20	4′4″
9	73	20	4′4″
10	80	20	5′6″
11A	87	20	5′6″
11	87	24	5′6″
12	94	24	5′6″
16	122	24	5′6″
18	136	26	5′6″
18A	136	30	5′6″
	Timber derricks		
W8	66	20	4′4″
W9	73	20	4′4″
W10	80	22	5′6″
W11	87	24	5′6″
W12	94	24	5′6″
W16	122	24	5′6″
W18	136	26	5′6″
W19A	136	30	5′6″

* The "size" numbers indicate the number of 7-ft. panels. The prefix letter W indicates a wooden derrick.

† Derrick heights are measured along the neutral axis of the derrick leg from the top of the derrick floor joists to the bottom of the water-table beams or bumpers, with a tolerance of plus 6 in. minus zero.

‡ Derrick bases are square and base square dimensions are measured between the neutral axes of adjacent legs, measured at the top of the derrick floor joists, with a tolerance of 5 in. plus or minus.

§ The water-table opening is square and the dimension given is a measurement inside or in the clear of the opening in the water table. A tolerance of 2 in. plus or minus is allowed.

time than is usual for a 136-ft. derrick. This advantage is especially important in deep drilling where a considerable percentage of the total time available for drilling is spent in changing bits.

In selecting a size and type of derrick appropriate for his purpose, the oil producer must consider not only its utility in drilling the well, but also its adaptation to subsequent maintenance operations during the period of production. A full-sized derrick of the kind used for rotary drilling is much higher and heavier than will be necessary for subsequent maintenance of the well, and in order to recover a part of the investment in the heavier and larger structure needed during the drilling stage, the drilling derrick is often disassembled and moved to a new location when the well is finished, and a smaller and lighter production derrick erected in its place. The larger structure may thus be used repeatedly and exclusively in drilling operations. Tearing down and reassembling derricks in this way are less feasible with timber than with steel derricks.

When the drilling derrick is replaced by a production derrick, it is important, if the well is producing, that it should be without a derrick for as short a time as possible, for in case of accident or any emergency, there would be no means of manipulating tools or heavy fittings in the well or about the casing head. Provision should be made for erection of the production derrick when the original foundations are constructed, so that if it is of smaller base, suitable foundation supports will be immediately available. Some operators erect the smaller operating derrick inside of the drilling derrick before the latter is removed. One style of drilling derrick is so designed that after the well is drilled the upper portion of the tower—generally the upper 84 ft. —can be detached from the lower portion and lowered integrally through it with the aid of blocks and some additional steel members supported by the lower structure. The 84-ft. production derrick rests on a 20-ft. square inner section of the original 26-ft. base provided for the higher structure. The lower portion of the original derrick is then removed and may be used in drilling another well, in combination with a new 84-ft. top.

Design of Derricks

The loading on a derrick used for drilling purposes is complex, often eccentrically applied and consequently difficult of analysis. The legs are, of course, always under compression, though important bending stresses may be imposed at times. The dead weight of the structure imposes very little stress on the girts and braces, but when wind load and the live load involved in operating drilling equipment, handling casing, etc., are applied, the horizontal and inclined members are subjected to stresses the magnitude of which depends upon the nature and direction of application of the load and the position of the member in the structure. Generally the horizontal girts are subjected to compressive strain, while the inclined braces assume the tensional loads. In addition, the individual panels are subjected to bending stresses and torsional strain, as, for instance, when tension is applied in a cable suspended from an off-center sheave in the crown block, toward one side of the structure. At times, in certain phases of the drilling process, impact loads and severe vibrational strains are imposed. Though the loading is complex and varies considerably with the character of the live load

TABLE XIV.—DIMENSIONS, WEIGHTS AND CAPACITIES OF A.P.I. STRUCTURAL STEEL DERRICKS

A.P.I. size	Dimensions: Height, ft.	Dimensions: Base size, ft.	Size of running legs, in.	Approximate weight, lb.	Safe working capacity, lb.: Silicon steel	Safe working capacity, lb.: Mild steel
8	66	20	$4 \times 4 \times \frac{1}{4}$	8,590	108,000	86,000
			$4 \times 4 \times \frac{3}{8}$	9,730	159,000	127,000
			$5 \times 5 \times \frac{3}{8}$	10,660	244,000	186,000
9	73	20	$4 \times 4 \times \frac{1}{4}$	9,420	108,000	86,000
			$4 \times 4 \times \frac{3}{8}$	10,560	159,000	127,000
			$5 \times 5 \times \frac{3}{8}$	11,490	244,000	186,000
10	80	20	$4 \times 4 \times \frac{1}{4}$	11,080	108,000	86,000
			$4 \times 4 \times \frac{3}{8}$	12,320	159,000	127,000
			$5 \times 5 \times \frac{3}{8}$	13,350	244,000	186,000
			$6 \times 6 \times \frac{3}{8}$	14,590	333,000	246,000
			$6 \times 6 \times \frac{1}{2}$	16,460	437,000	323,000
11A	87	20	$4 \times 4 \times \frac{1}{4}$	11,590	108,000	86,000
			$4 \times 4 \times \frac{3}{8}$	12,940	159,000	127,000
			$5 \times 5 \times \frac{3}{8}$	14,080	244,000	186,000
			$6 \times 6 \times \frac{3}{8}$	15,530	333,000	246,000
			$6 \times 6 \times \frac{1}{2}$	17,600	437,000	323,000
12	94	24	$4 \times 4 \times \frac{1}{4}$	14,390	108,000	86,000
			$4 \times 4 \times \frac{3}{8}$	15,940	159,000	127,000
			$5 \times 5 \times \frac{3}{8}$	17,080	244,000	186,000
			$6 \times 6 \times \frac{3}{8}$	18,530	333,000	246,000
			$6 \times 6 \times \frac{1}{2}$	20,800	437,000	323,000
16	122	24	$5 \times 5 \times \frac{3}{8}$	22,870	244,000	186,000
			$6 \times 6 \times \frac{3}{8}$	24,840	333,000	246,000
			$6 \times 6 \times \frac{1}{2}$	27,530	437,000	323,000
			$6 \times 6 \times \frac{5}{8}$	30,120	537,000	398,000
18	136	26	$6 \times 6 \times \frac{3}{8}$	30,220	333,000	246,000
			$6 \times 6 \times \frac{1}{2}$	33,120	437,000	323,000
			$6 \times 6 \times \frac{5}{8}$	36,020	537,000	398,000
			$8 \times 8 \times \frac{1}{2}$	37,980	645,000	465,000
			$8 \times 8 \times \frac{5}{8}$	41,610	800,000	577,000
			$8 \times 8 \times \frac{3}{4}$	45,750	952,000	687,000
18A	136	30	$6 \times 6 \times \frac{5}{8}$	41,920	537,000	398,000
			$8 \times 8 \times \frac{1}{2}$	43,470	645,000	465,000
			$8 \times 8 \times \frac{5}{8}$	47,090	800,000	577,000
			$8 \times 8 \times \frac{3}{4}$	51,230	952,000	687,000

imposed, it is possible to approach the design of a derrick by graphical or mathematical analysis and proportion each member of the structure in accordance with the maximum stress that it will be called upon to sustain in normal drilling operations.

Dead-load Capacity of a Derrick.—In selecting derricks for drilling purposes the engineer must consider the maximum loading likely to be imposed. Generally the greatest dead load that the derrick will be called upon to support is that of the heaviest column of casing to be inserted in the well. This, of course, can be computed if the size and landing depth of each string of pipe to be used can be determined in advance. To the dead load of the casing, a friction allowance of 25 or 50 per cent should be added. For example, if 5,000 ft. of 10¾-in. 45.5-lb. casing is to be set, and 1,250 ft. (25 per cent) is added to cover friction, the probable dead load imposed on the derrick will be $6{,}250 \times 45.5 = 284{,}375$ lb.

Maximum strain is imposed on the derrick in pulling on "frozen" casing, and some engineers select derricks strong enough to resist a tensional strain sufficient to pull the casing apart. For example, 10¾-in. 45.5-lb. medium-carbon seamless casing has a maximum joint pull-out strength of approximately 550,000 lb. Table XXIV, page 421, shows computed pull-out strengths of various sizes and weights of A.P.I. standard casings.

TABLE XV.—EXPOSED SURFACE AREAS AND HORIZONTAL COMPONENT OF WEIGHTS OF PIPE SETBACKS

Derrick height, ft.	Assumed length of stacked pipe, ft.	Exposed areas for A.P.I. wind loading	Horizontal component of wind load, lb.	Combined horizontal load at finger board: pipe weight and wind load, lb.
66	2,000	1′9″ wide, 44′0″ high	410	762
73	4,000	2′5″ wide, 65′0″ high	1,134	1,642
80	2,430	3′11″ wide, 67′6″ high	2,671	3,306
87	2,430	3′11″ wide, 67′6″ high	2,671	3,306
94	2,430	3′11″ wide, 67′6″ high	2,671	3,306
122	3,240	3′11″ wide, 90′0″ high	3,561	4,563
136	8,000	5′8″ wide, 90′0″ high	7,747	8,138

Another method of estimating the necessary dead-load strength of a derrick is to assume that it must be capable of withstanding the strain necessary to break the hoisting cable. Table XXI, page 247, gives ultimate strengths of various grades of 6×19 wire ropes. If, for example, a 1-in. 6×19, grade L cable is strung with nine lines between the crown block and the hoisting block, the maximum dead load to which the derrick can be subjected will be approximately nine times 66,000 lb., or 594,000 lb.

Manufacturers marketing A.P.I. standard equipment are required to rate their derricks according to the maximum dead loads that they are designed to support. The engineer has merely to refer to the manufacturers' tables giving ratings for the different sizes and weights of derricks to select one appropriate for his needs. Manufacturers customarily use a safety factor of from two to four in designing derricks, so that the ultimate load at which a derrick will fail is generally at least double the

rated safe load. Table XIV gives the ratings for A.P.I. standard steel derricks marketed by one American manufacturer. It will be noted that this manufacturer uses two different materials in the construction of derricks: the ordinary mild structural steel having a yield point of about 20,000 lb. per sq. in., and a special silicon steel having a tensile strength 36.5 per cent greater than that of ordinary steel. With the latter material, a lighter derrick may be selected for the same loading.

Wind Loads on Derricks.—The wind load imposed on a derrick is a factor that must be taken into consideration in its design. American Petroleum Institute specifications provide that A.P.I. standard derricks must be designed safely to withstand the pressure of a wind having a velocity of 70 m.p.h., which develops a horizontal pressure of 11.76 lb. per sq. ft. on all surfaces directly exposed to it. In computing the surface exposed to the wind, it should be assumed that the wind pressure is applied against the outside of one side or panel of the derrick and on the inside of the opposite panel. The A.P.I. specifications also require that in computing the effective wind load, it be assumed that a setback of drill pipe of a specified size is leaning against the "finger board" of the derrick at an angle of $2\frac{1}{2}$ deg. from the vertical, racked in its normal position between the finger and the adjacent side of the derrick. In addition to the wind load against this setback of drill pipe leaning against one side of the derrick, there is a horizontal component of the weight of the pipe itself tending to overthrow the derrick. Table XV specifies wind surfaces presented and horizontal components of weights of drill-pipe setbacks for derricks of different heights, recommended for design purposes by the A.P.I. Committee on Standardization of Rigs and Derricks. The horizontal wind pressure and horizontal component of the weight of the pipe setback is assumed to be concentrated at a height above the derrick floor equal to one-half the height of the setback and to be applied in a direction perpendicular to the finger board and 36 in. distant from the side of the derrick adjacent to the "finger."

The actual wind-load pressure applied to the exposed surfaces of the derrick and pipe setback may be computed with the aid of the following formula: $P = 0.0024V^2$. Here V is the assumed or estimated wind velocity in miles per hour and P is the pressure exerted in pounds per square foot of exposed area. For example, a 120-m.p.h. wind develops a pressure of 34.56 lb. per sq. ft. of exposed surface. This is about the maximum likely to be attained in most regions, and some manufacturers design their derricks to provide security against this amount of horizontal pressure.

The influence of wind pressure on the structure as a whole is offset by bolting the four legs securely to the four foundation piers or substructure. Though a properly designed derrick is supposed to be self-supporting against all horizontal loads when bolted to the foundations in this way, many operators provide additional security against overtoppling by guying to near-by stationary objects on the ground or to "deadmen" of timber, steel or concrete buried in the earth, usually about 150 ft. distant. From 8 to 24 guy wires may be used, that is, from 2 to 6 on each leg. These are attached at two or three points between the derrick crown and the floor and are led off from the structure in the direction of the diagonal plane through the opposite leg. Guy wire is appropriately $\frac{3}{8}$ in. in diameter and composed of 7 strands of galvanized wire.

Combined Derrick Loads.—In analyzing the loads that may be applied to a derrick used in drilling operations, we must consider not only the weight of the derrick itself and the "dead" loads that may be suspended from it, but also the live loads occasioned by forces applied in handling equipment and conduct of the work. The dead load of the derrick itself is a considerable item, aggregating in the case of a 136-ft. steel derrick some 30,000 to 50,000 lb. A long column of large-diameter casing suspended in the well from the derrick crown may impose a load of as much as 300,000 lb., to which should be added at least 25 per cent, or another 75,000 lb. to

cover friction if the column of pipe has to be lifted. In pulling upward on "frozen" casing or drill pipe in the well, an additional load may be imposed by the line pull from the draw works or calf wheel of perhaps 20,000 lb. This may be multiplied as many as eleven times by the hoisting block producing a total live load of as much as 220,000 lb. This load is perhaps quickly applied and is therefore productive of impact stress, for which a high safety factor must be imposed. Though the wind load is generally regarded as being applied at right angles to the side of the derrick, it is resolved by the foundation bolts or guy wires into compressive strain on two of the derrick legs. If we assume a unit pressure of, say, 30 lb. per sq ft., applied on two sides of the derrick, over a total area of 425 sq. ft. for each side, and upon a setback of drill pipe presenting an additional area of about 360 sq. ft., wind pressure alone may exert a strain of about 30,000 lb. This, too, is an impact load in that it may be applied suddenly.

The aggregate of these various loads may reach surprising totals if sumultaneously applied and if appropriate multipliers are used to evaluate properly the impact stress. Authorities generally agree that impact loads, owing to the suddenness with which they are applied, develop stresses as great as four or five times the actual force exerted. If we apply a factor of four to the impact forces suggested in the preceding paragraph, we may attain a maximum strain equivalent to a dead load of 1,425,000 lb., or upward of 700 tons, in the event that the different possible loads are applied simultaneously. This, however, is a maximum figure, and it would be quite unusual for all the possible loads to be applied simultaneously. The load imposed on a derrick may thus at times be in excess of the rated safe working load. Handling long strings of heavy casing or pulling on "frozen" drill pipe or casing with powerful twin-cylinder engines operated by high steam pressure, with the force multiplied many times by massive hoisting blocks, with loads suddenly applied, imposes a strain that occasionally causes buckling or even complete collapse of the derrick.

After the various loads that the derrick may be called upon to support have been estimated, the character and magnitude of the stress in each member of the structure may be determined by the usual methods of stress analysis applied to framed structures. The problem, however, is a difficult one and can best be approached by the methods of graphostatics. Each side of the structure will yield a somewhat different result. Stress diagrams resulting from crown-block loads and stresses induced by operation of mechanical equipment are more complex, and space does not permit of discussing them here. They are to be regarded as difficult problems even for the engineer skilled in structural design and are scarcely within the province of the petroleum engineer.

Design of Various Parts of Steel Derricks.—The derrick legs function as columns in compression and are unsupported between adjacent panel points. Once the maximum dead load to which the derrick is likely to be subjected has been determined, the necessary minimum cross section of the leg members is determined by dividing the total load by four and substituting this value for P in the following equations:

(1) If ratio of $\frac{L}{r}$ is not in excess of 60,

$$\frac{P}{a} = 15{,}000$$

(2) If ratio of $\frac{L}{r}$ is greater than 60,

$$\frac{P}{a} = \frac{18{,}000}{1 + \frac{L^2}{(18{,}000)(r^2)}}$$

In these equations, P is the total compression load in pounds on one leg of the derrick

a is the gross cross-sectional area of the derrick leg in square inches; L is the unsupported length of the column or leg element between adjacent panel points in inches; and r is the corresponding least radius of gyration of the column cross section in inches. American Petroleum Institute prescriptions require that for the main compression members in a derrick, the value of L/r shall not exceed 120. The width-to-thickness ratio of angle leg members is not permitted to exceed 16 to 1. For bracing and other secondary members in compression, L/r may be as high as 200. American Petroleum Institute specifications provide that steel derricks shall be constructed of structural steel or pipe having a yield point of not less than 33,000 lb. per sq. in. However, pipe reinforcing members in the legs may be of A.P.I. grade A pipe having a minimum yield point of 30,000 lb. per sq. in. All parts of the derrick must be so proportioned that the unit stress in pounds per square inch shall not exceed the following values:

	Structural steel (A.S.T.M. A7), lb. per sq. in.	Structural silicon steel (A.S.T.M. A94), lb. per. sq. in.
Members in tension	20,000	27,300
Rivets	15,000	
Members in compression:		
(L/r up to 60)	15,000	20,800
(L/r greater than 60)	18,000	27,000
Members subjected to bending stresses:		
Tension on extreme fibers	20,000	27,300
Compression on extreme fibers	22,500	30,700
Members subjected to shearing stress:		
Rivets, pins, turned bolts in reamed holes	15,000	

The "water-table" beams must be of adequate strength to support safely the crown-block load. Its safe load capacity should be at least equal to the safe dead-load capacity given on the derrick name plate, except that it need not exceed 570,000 lb. The following formula may be used in computing the safe load capacity of the water-table beams:

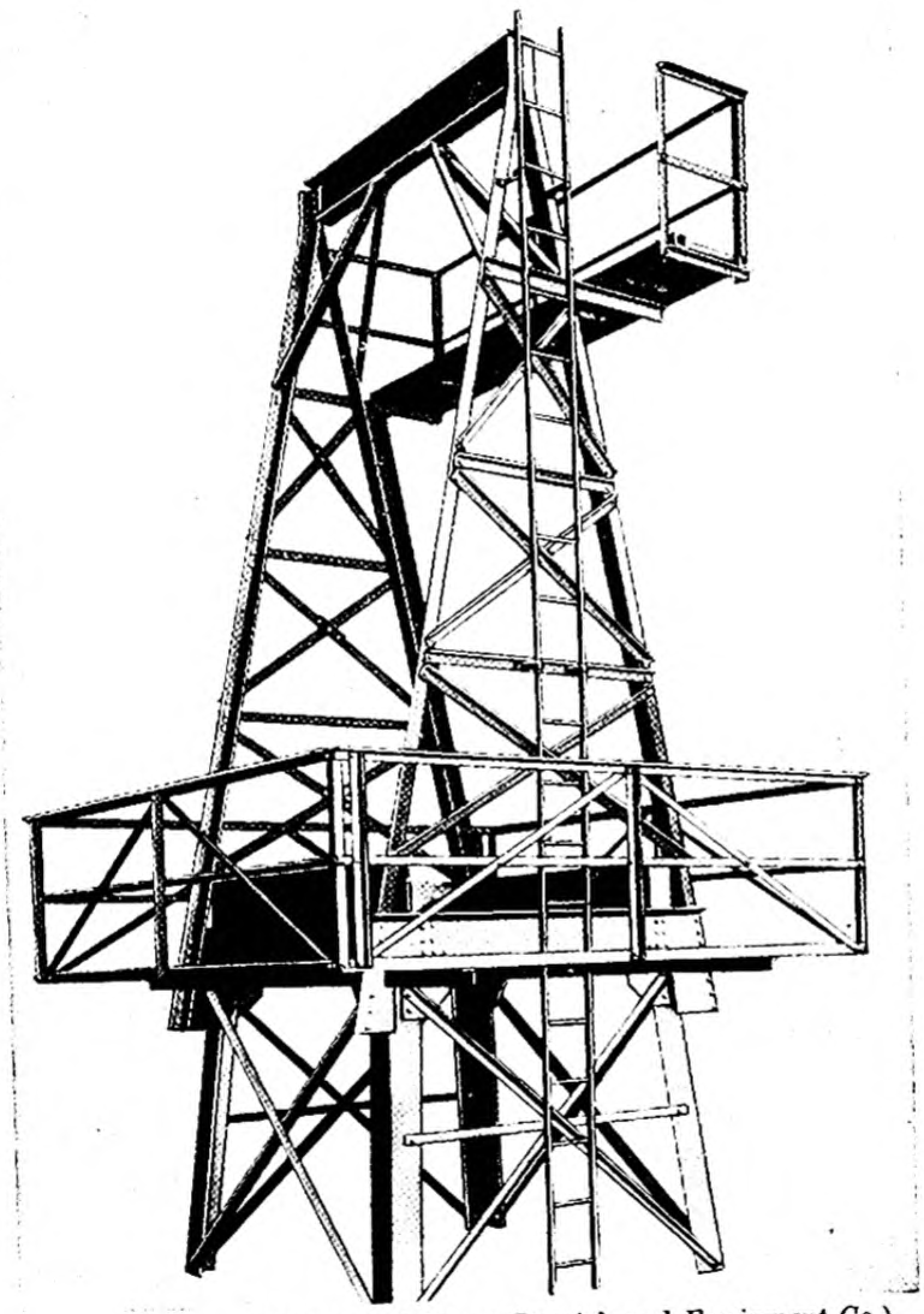
$$W = \frac{12M}{L} = \frac{12(Sm)(fc)}{L}$$

Here, W = safe load capacity of two water-table beams, in pounds (or 570,000 lb. max.); M = bending moment, in inch-pounds; L = distance between neutral axis of legs at the bottom of the water-table beams, or between the load axes if the derrick is reinforced, in inches; Sm = section modulus of one of the water-table beams; fc = allowable unit stress on extreme fibers of the beams.

Structural Details of Steel Derricks.—Differences are noted in the structural details of steel derricks, particularly in the arrangement of braces between girts and in the size and shape of the window openings in the lower panels on different sides of the structure. Earlier types of derricks utilized conventional arrangement of braces with two cross members in each panel between diagonally opposite girt-leg intersections, the girts being spaced 7 ft. apart. In the heavier lower panels of larger structures, four cross braces are sometimes used, extending from the mid-point of

each girt to diagonally opposite girt-leg intersections in both adjacent panels. Double bracing of this type reduces the unsupported length of both girts and braces and permits the braces to function either as tension or compression members, as circumstances may require. In some designs, short vertical struts connect the points of intersection of the diagonal braces with the center points of the adjacent girts.

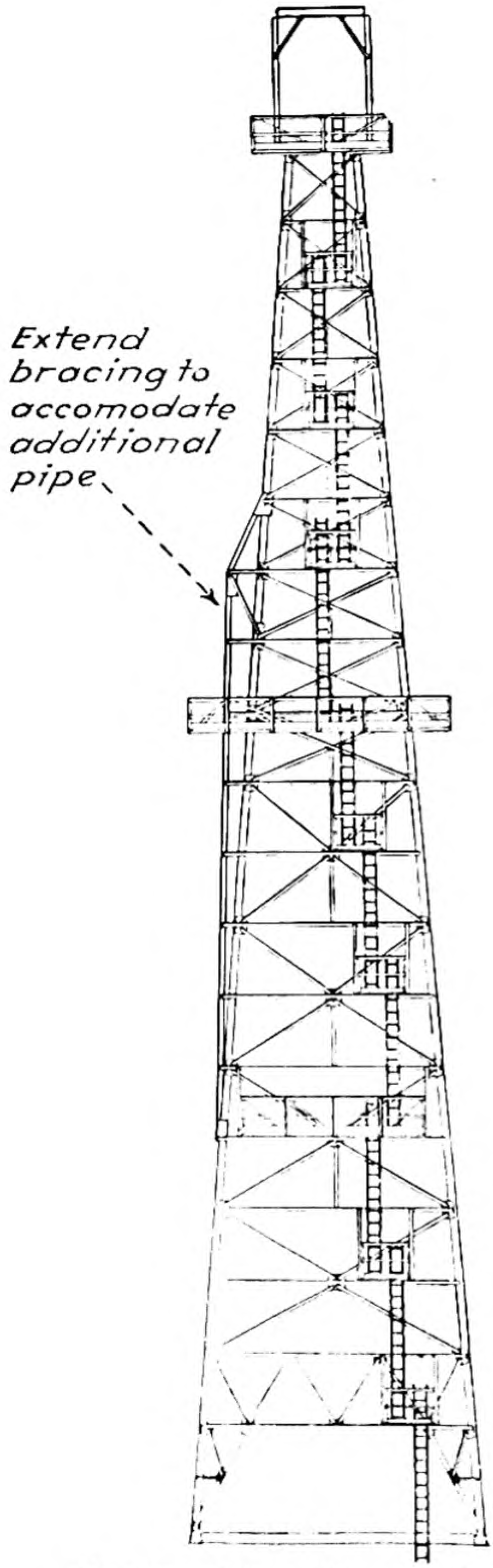
The *K* type of bracing used by some derrick manufacturers provides an inclined brace from the center of each horizontal girt to the mid-points of the legs in the adjacent panels. The braces thus form a diamond-shaped opening in each panel. The inclined braces may, in turn, be supported by short secondary braces from their



(Courtesy of Emsco Derrick and Equipment Co.)

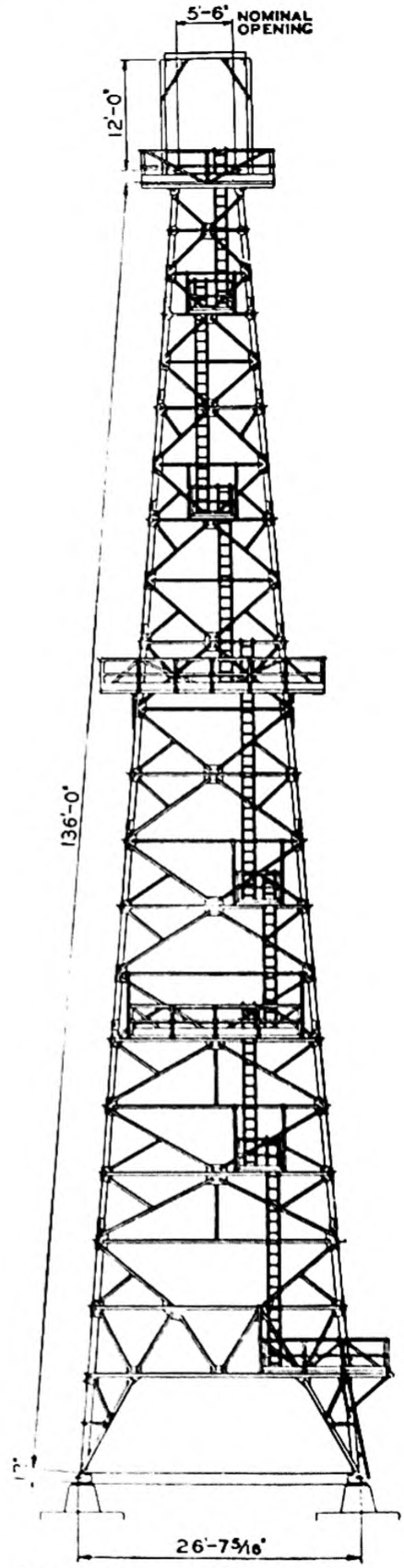
FIG. 34.—Construction of gin pole, working platform and crow's nest of "Emsco" type *R* derrick.

mid-points to the adjacent leg-and-girt intersections (see Figs. 36 and 37). Girts are spaced 7 ft. apart. In some parts of the structure, the normal arrangement of girts and braces may, be interrupted, redundant members that do not receive stress of any magnitude being omitted, while additional bracing may be added where abnormal stresses require extra reinforcement.



(Courtesy of Emsco Derrick and Equipment Co.)

FIG. 35.—Bulge type of structural steel derrick.

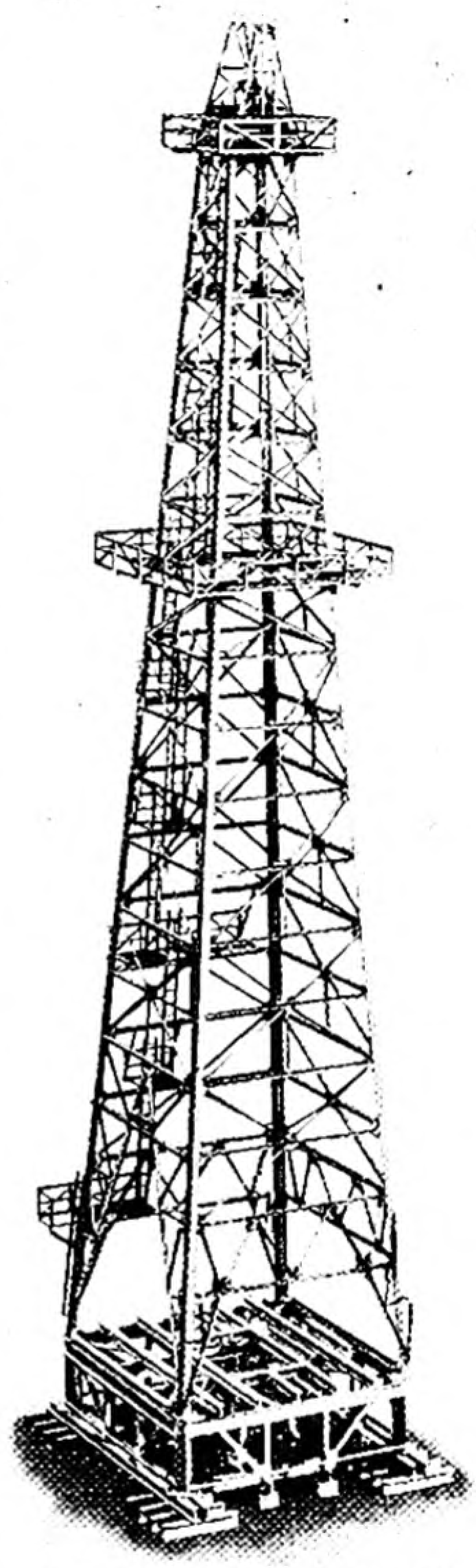


(Courtesy of Emsco Derrick and Equipment Co.)

FIG. 36.—Standard 136-ft. A.P.I. structural steel derrick, illustrating *K*-type bracing.

Whatever form of bracing is used, the purpose should be to accomplish an equal distribution of stress, utilize a minimum of material and eliminate redundant members; also, to prevent vibration by reducing the unsupported length of members subjected to compression, so that they will not buckle under stress.

One type of derrick features a design in which adjacent end joints in leg members are staggered, so that only two vertical leg joints occur in each panel and these are diagonally opposite. The manufacturer claims that this construction results in a stronger, more rigid structure, less subject to buckling or torsional distortion at the leg joints.



(*Courtesy of Emsco Derrick and Equipment Co.*)

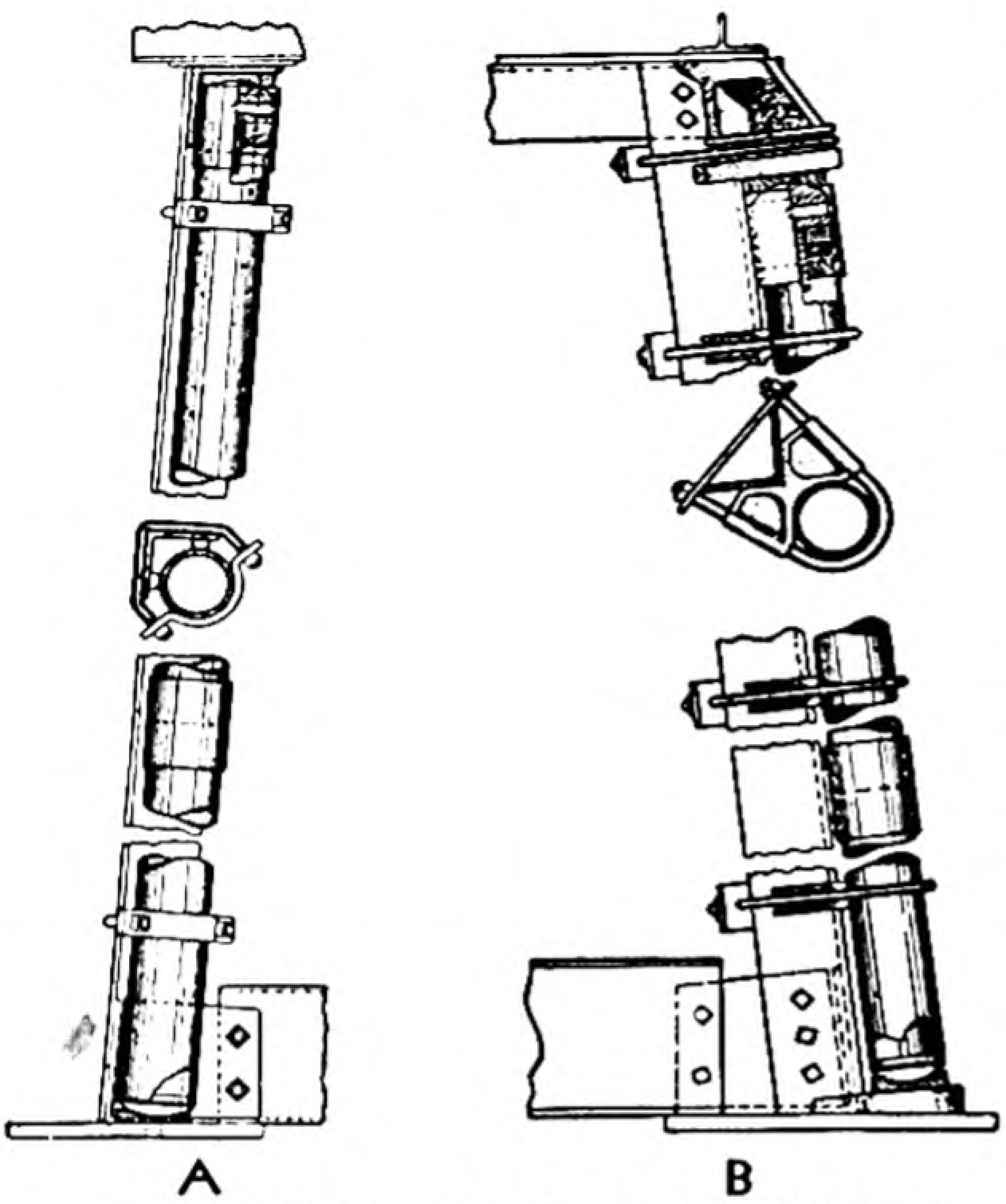
FIG. 37.—"Emsco" type *R* steel derrick and substructure.

Leg members, girts and braces are bolted together, web or strap reinforcing plates of appropriate size and weight being employed at each joint. Two-bolt construction, as the name implies, provides two bolts to attach each structural member to the web or strap connecting plates. Two I beams and two channels bolted together through angle plates form the water table, which is bolted to special brackets that provide a rigid connection to the top ends of the derrick legs (see Fig. 34). The lower ends of the derrick legs rest on substantial base plates and are bolted to the foundation piers through substantial "base corners" that also provide a means of attaching the legs to the base channels. Additional reinforcement for the derrick legs may also be provided by inserting tubular "relegs" on the outside or in the V of the leg angles, extending from the base corners to the water table, clamped at intervals to the legs (see Fig. 38). The legs may also be reinforced by outside wing braces at the level of the first girt where the maximum bending stress is likely to be developed (see Fig. 39).

The lower panels of each side of the derrick are specially designed to receive or support a certain part of the drilling equipment. The arrangement of "windows" in the lower part of each side of the derrick structure varies with the method of drilling—*i.e.*, churn or rotary or combination—and with the custom of the region. Figure 39 indicates the arrangement of structural members forming different sides of cable, rotary and combination rigs, as recommended by A.P.I. specifications. The height of the V-window opening in a steel derrick designed for rotary drilling is standardized at 23 ft. 8 in. Joints of drill pipe and casing are brought into the derrick and up-ended through this window. Because of its large size, cutting vertically across three of the larger derrick panels, special reinforcement members are grouped about it. The opening in which the draw works is placed is 20 ft. long and 7½ ft. high. For cable and combination rigs, provision must also be made for supporting the bull and calf wheels in their proper positions in suitable window openings.

The "gin pole" at the summit of the derrick provides a means of hoisting the crown block into position. Usually it consists of two A frames, based on oppo-

site beams of the water table, supporting a connecting crossbeam extending across the center of the water-table opening and providing a means of supporting at its center, a sheave capable of suspending the crown block and necessary hoisting tackle (see Fig. 34). The gin pole of a 122-ft. derrick and smaller sizes must be capable of supporting a load of 6,000 lb.; that of a 136-ft. derrick must be capable of supporting a 10,000-lb. load. The clearance between the horizontal header of the gin pole and the tops of the water-table beams is standardized at 8 ft. for derricks under 122 ft. in height; 10 ft. for 122-ft. derricks; and 12 ft. for 136-ft. derricks.

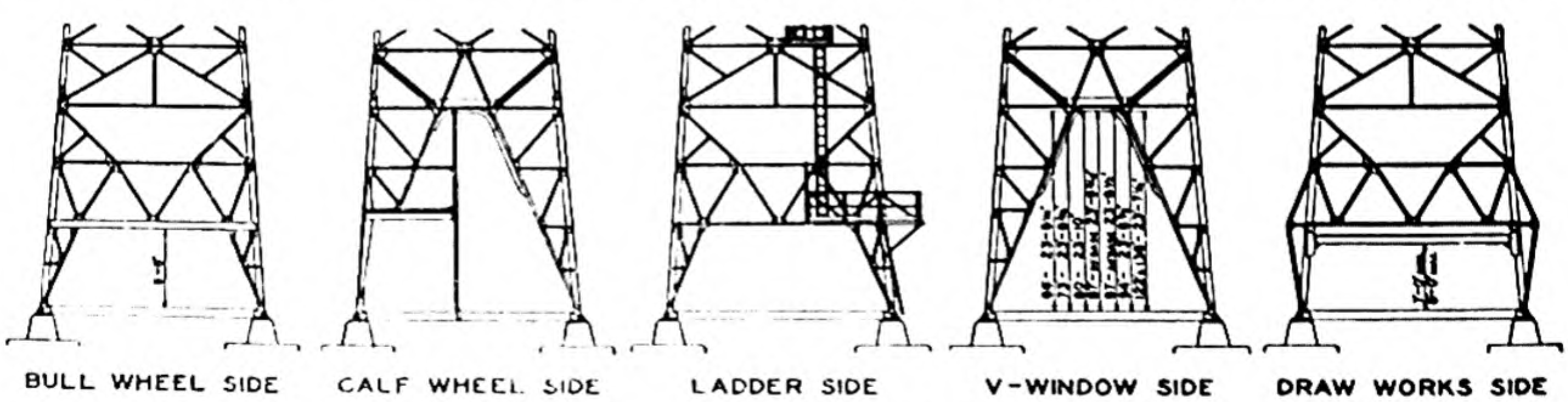


(*Courtesy of Lee C. Moore & Co., Inc.*)

FIG. 38.—Use of tubular reinforcing members in strengthening derrick legs. *A*, inside reinforcement; *B*, outside reinforcement.

Steel ladders are provided up one side of the derrick to the crown. To reduce the distance that a man might fall while ascending or descending the ladderway, several ladders are used, offset from each other and terminating at railed "ladder-landing platforms," spaced at uniform intervals on the outside of the tower. For added safety, a semicylindrical screen frame or cage may surround the outside of each ladder. The crown safety platform or crow's nest, providing a working platform about the crown block and gin pole, is also equipped with a safety railing (see Fig. 34). The floors of these platforms may be of plank or steel grating, perhaps covered with nonskid steel floor plates.

At the level of the "fourble" board or quadruple board, about 76 ft. vertically above the derrick floor, a safety platform with guard railing extends around all four sides of the derrick (see Fig. 40). This is for the convenience and safety of the derrick man who is required to work in the derrick at this elevation in racking drill pipe.



(*Courtesy of Emsco Derrick and Equipment Co.*)

FIG. 39.—Arrangement of structural members forming different sides of A.P.I. standard derricks.

For his further protection against wind and weather, a small lean-to house may be attached to the outside of the derrick at the level of the fourble board and conveniently placed with reference thereto. This is large enough to shelter only the derrick man

during the few minutes while he is waiting between times when he is required to manipulate elevator clamps and guide individual stands of drill pipe to or from their racked position against the quadruple board.

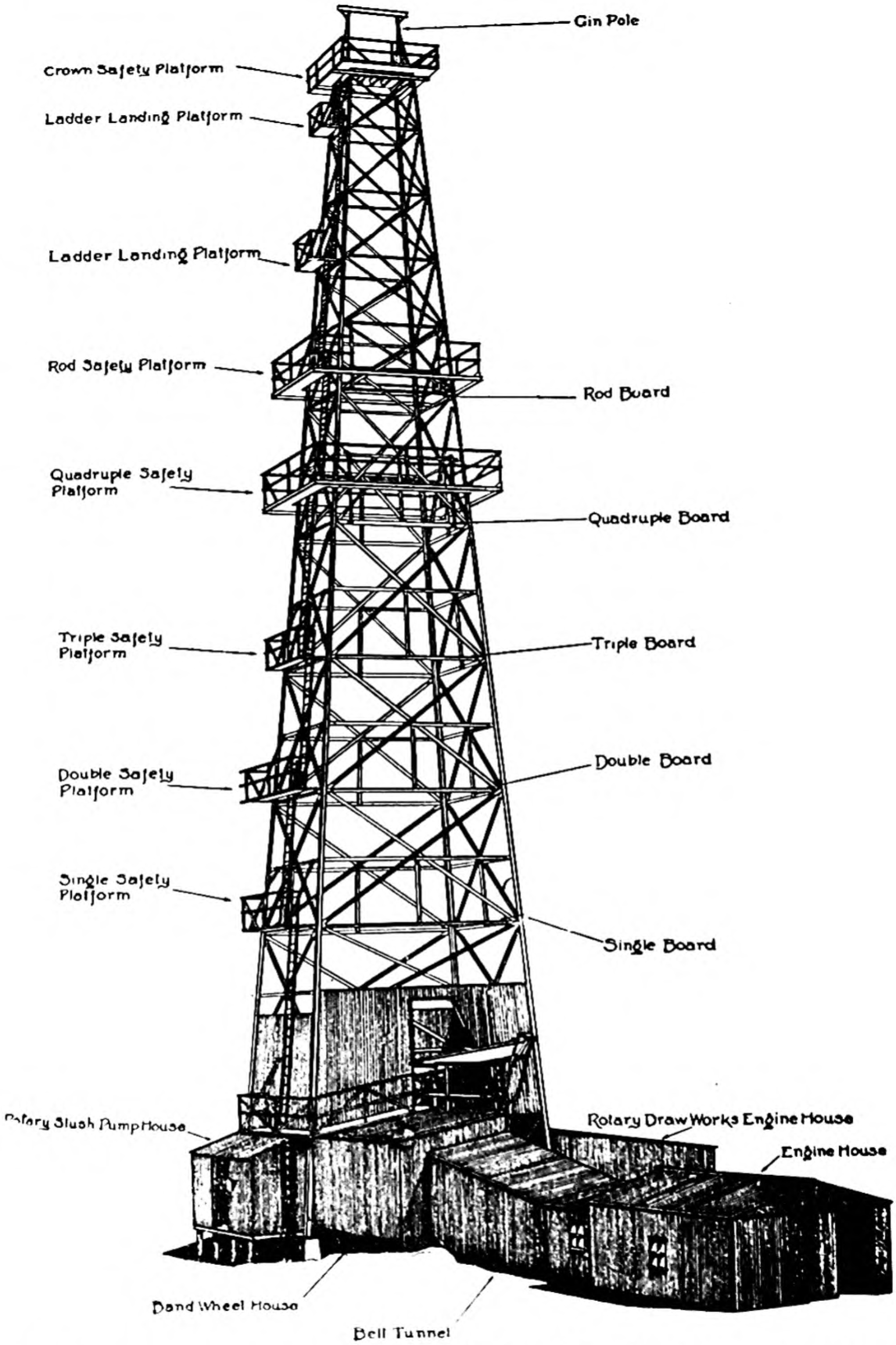
Custom throughout the oil fields recognizes certain elevations in the derrick at which narrow platforms inside the framework of the tower may be provided, and names designating their position or purpose are in common use (see Fig. 40). Thus, as indicated in the foregoing paragraph, the quadruple board (or fourble board) is a narrow platform on which the derrick man may stand in racking drill pipe when it is stacked against the finger board in four-joint stands. The triple board, double board and single board, situated at successively lower elevations in the derrick, may be used by the derrick man in stacking stands of drill pipe or casing of shorter lengths, or the "kelly" and swivel when disengaged from the hook and hoisting block. The "rod board" above the quadruple board, is used in suspending sucker rods in the derrick during repair operations in the later period of production. Not all these platforms are necessarily provided in the derrick at any one time. Still another platform with guard rail may be provided on the roof of the pump house, at the foot of the main ladderway up the side of the derrick.

Timber Derrick Design

Much of what has been said in the foregoing section on the design of steel derricks applies also to the design of timber derricks. American Petroleum Institute standards prescribe the same standard sizes and dimensions for timber derricks as for steel derricks and they are required to meet the same load capacities. However, because of the fundamental differences in the nature of the materials, design formulas for timber derricks necessarily differ from those appropriate for steel structures.

A safety factor of 2¼ is recommended for timber structures of this character by the American Society for Testing Materials and the U.S. Bureau of Standards. The Forest Products Laboratory finds that timber yields slowly to stress and that long-period loading requires use of a safety factor 1½ times that appropriate for short-period loading. Heavy loads occasionally applied to derricks used in drilling operation are seldom of more than 5 min. duration and are to be regarded generally as short-period loads.

Tests made in the engineering laboratories of the University of California show that the ultimate strength of columns built of planks nailed together to form a trough of L section—such as is used in the construction of legs for timber derricks—differs materially from the ultimate strength of solid timber columns of equivalent cross section. When 2-in. planks are combined in the way usually employed in building the corner legs of timber derricks, each pair of planks forming an L-shaped section may act independently of other pairs in the same derrick leg. These trough-shaped columns must have an L/r ratio of not more than 38 and are limited in safe-load capacity by tendencies inherent in timber as a structural material. It is probably unsafe to rely upon timber for more than about 75 per cent of its apparent compressive strength as determined by ordinary test methods. As the ratio of width to thickness of the component members of the leg section increases, derrick legs tend to fail in torsion rather than compression. Torsional stress is the limiting factor when the value of this ratio exceeds 5. When the width of the leg is six times its thickness, it will normally fail at about 67 per cent of the compressive strength of the material. When the ratio is 7 to 1, failure is likely to occur at about 56 per cent of the compressive strength. Timber is not a uniform structural material. Inherent irregularities due to presence of knots, direction of grain, irregularities induced by methods



(*Courtesy of American Petroleum Institute.*)
FIG. 40.—Derrick and housing for combination rig, showing names of various parts.

of cutting and seasoning are inevitable and allowance must be made for them by employing a larger safety factor than would otherwise seem necessary.

American Petroleum Institute specifications prescribe that the thickness of timber used in derrick leg construction shall be not less than 2 in., that ends of abutting leg members shall be properly faced to provide a uniform bearing throughout the structure and that splices in leg members shall be at least 2 ft. apart. The safe load capacity of a derrick leg may be computed with the aid of the following formula:

$$P = \tfrac{3}{2}(AC)$$

Here P is the safe load capacity of the leg in pounds; A is the cross-sectional area of the leg in square inches; C is the allowable working stress in pounds per square inch. Suggested values of C for use in this formula are as follows:

Grade of lumber	Short solid columns	Built-up columns	
		2 × 8's or 2 × 10's	2 × 12's
Southern pine: No. 1 common, dense, with slope of grain limited to 1 in 10	1,050	1,050	1,050
Douglas fir (coast type):			
Structural	1,100	1,050	950
Common structural	1,000	1,000	900

The safe load capacity of a timber gin pole can be computed with the aid of the following formula:

$$P = \frac{0.274AE}{(L/d)^2}$$

Here P is the safe load capacity in pounds; A is the cross-sectional area of the gin pole, in square inches; E is the modulus of elasticity of the timber species used; L is the unsupported height of the column, in inches; and d is the shortest side of the column, in inches.

Derrick Foundations

To distribute loading properly and to keep all mechanical equipment in proper alignment, the derrick should be provided with a rigid foundation. This may be of either timber or concrete; the latter material is preferable, especially if the well to be drilled is a deep one and heavy loads are to be imposed. The size of the foundation to be provided may be determined only after an inspection of the subsoil upon which the foundation is to rest. Alluvial soil is capable of supporting a load of only 1,000 lb. per sq. ft. without yielding; soft clay or wet sand, 2,000 lb.; firm, dry loan, 5,000 lb.; compact sand, gravel and boulders, 10,000 lb; rock, 30,000 lb. Having estimated the total dead load of the derrick and the live load to which it will be subjected, the total is divided equally among the four legs and a footing constructed for each leg having a base of such size as will distribute the load over an area of subsoil capable of supporting it. It is very important that the foundation be absolutely rigid and unyielding, for if one corner yields under strain, the total load is thrown on the two adjacent

legs and failure of the structure may result. It is said that most derrick failures are caused by unequal loading of the derrick legs, caused by subsidence of some part of the structure under strain. It is claimed that wooden derricks, because of their greater flexibility and ability to yield without failure, adjust themselves better to slight changes in the position of the foundations than steel derricks.

Wooden derrick footings are generally constructed of heavy timbers, often 8 by 10 in. or larger, nailed together to form a pyramidal structure of appropriate height and with a base of such size as to spread the load over a sufficient area. The base of the footing is preferably buried in the earth sufficiently to minimize the tendency of the subsoil to shift or flow under the load imposed. The derrick footing cannot yield unless the soil is pressed out from beneath it. Soil, sand or gravel yields more readily while wet than when it is dry; hence proper drainage of the subsoil under the derrick footings should receive attention. This may be accomplished to some extent by simply heaping the soil from the excavation to form a mound about the footing. Gravel tamped into the excavation about the timber provides a firmer base in soft soils.

Concrete Derrick Footings.—For deep wells, where long, heavy strings of casing must be handled, concrete footings are always to be preferred, whether the derrick be of steel or timber, but especially where a steel derrick is to be used. The greater security against collapse of the structure provided by concrete foundations, greater resistance against decay and better distribution of stress among all parts of the rig assure longer life to the derrick, lower maintenance costs and, most important of all, safety of personnel. Concrete piers, walls, foundation blocks and mats provided for the support of derricks to be used in drilling operations must be carefully designed and accurately constructed so that the superstructure may be erected on them without distortion and so that they will be firm and unyielding under the maximum loads that may be imposed. If the site selected for the rig is on a hillside or is otherwise irregular in contour, a certain amount of grading may first have to be done before the foundations are constructed. Unless the derrick floor is to be high above the ground level, a cellar must be excavated and, for rotary drilling, a mud pit. The corners and center line of the rig are laid out on the ground and levels are accurately determined by instrumental survey methods. Lumber forms are then constructed for the concrete structures; cement, coarse aggregate and sand are delivered; a water supply is provided and arrangements are made for mixing and pouring concrete. A small portable concrete mixer, capable of handling a one- or two-sack batch, will be adequate for mixing the concrete in many cases; but where massive blocks of concrete or large and heavy walls and piers are to be poured, a larger engine-driven mixer must be employed.

The concrete ingredients should be measured carefully to obtain proper proportions, a mixture of 1 cu. ft. of cement to 2 of sand and $3\frac{1}{2}$ of coarse, broken rock or gravel ($+\frac{1}{4}$ in. $-$ 2 in.), mixed with 7 gal. of water, being appropriate for most purposes. After mixing, the concrete should be placed carefully in the forms in such a way as will avoid segregation of the constituents or formation of voids. If it is desirable to erect the rig on the foundations as soon as possible, less water may be used in the mix, or more cement; or an accelerator (such as calcium chloride) may be added to the concrete to hasten its setting and hardening. Concrete prepared in this way, should develop a compressive strength of not less than 1,000 lb. per sq. in. in 7 days, and not less than 2,000 lb. in 28 days.

Design of concrete foundations for drilling rigs will vary with the type of rig (*i.e.*, cable-tool, rotary or combination), with the size and weight of the equipment as determined by the depth to which it is proposed to drill, by the nature of the terrain, character of soil, custom of the region and preference of the operator. A

certain amount of headroom must be preserved below the derrick floor for subfloor equipment (about 12 ft. for rotary drilling). This may be provided either by excavating a cellar below the level of the derrick floor, or by elevating the derrick sufficiently above the natural ground level so that no cellar is necessary. Often a compromise is reached by excavating a shallow cellar and elevating the derrick floor moderately. On a steep hillside, it may be necessary only to excavate a "bench" on the high side, the natural slope of the ground affording ample headroom on the lower side. Figure 41 illustrates a typical foundation design for a rotary rig of the kind frequently used

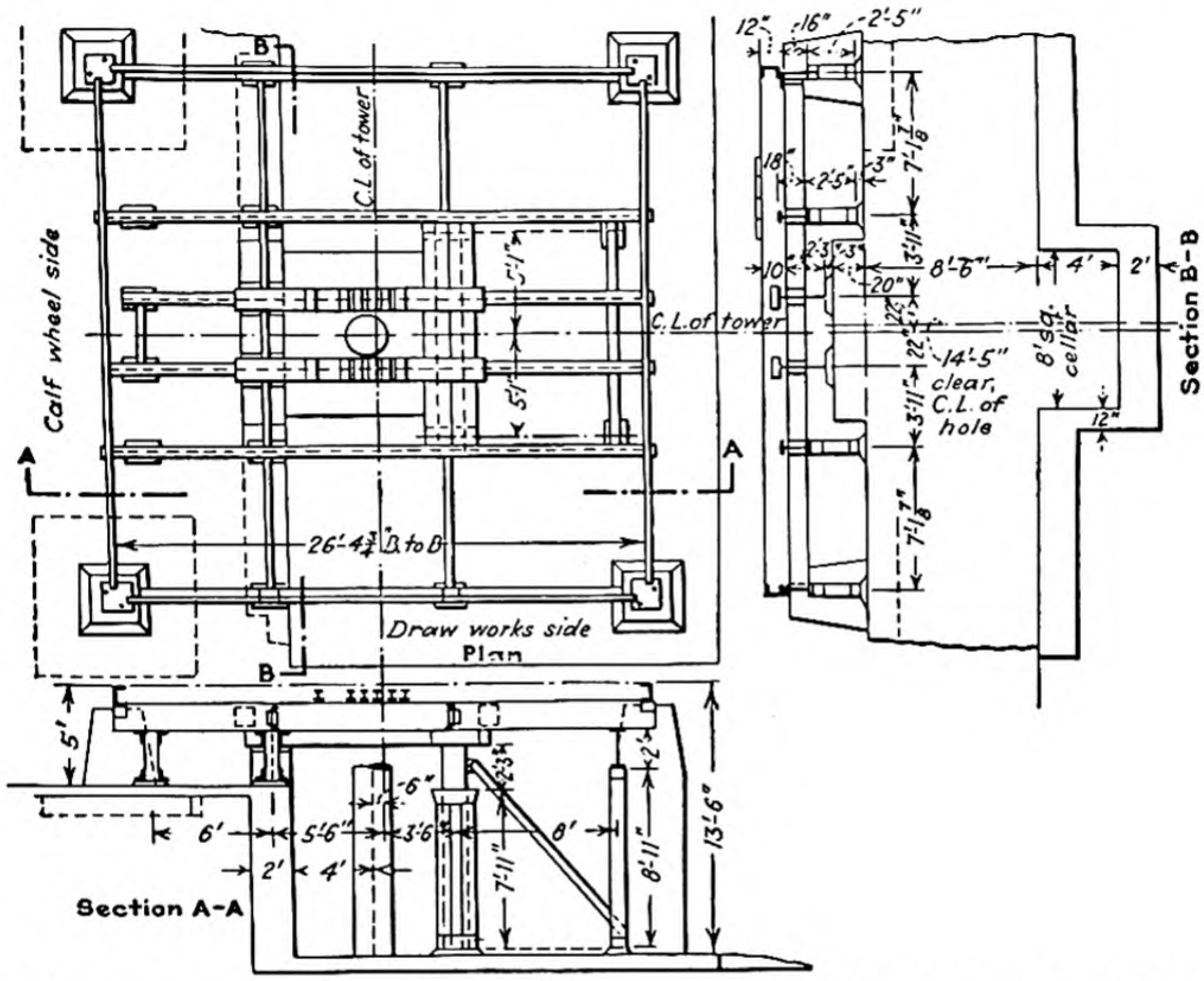


FIG. 41.—Concrete and steel foundation plan for a 122-ft. California-type combination rig.

in the California fields for drilling to depths of 8,000 to 12,000 ft. There is a trend toward use of a type of foundation that will permit of salvage, after the well has been completed, of as large a part of the investment in derrick foundations as possible. Some of the steel or timber beams and posts used to support the heavy drilling equipment will be unnecessary after the drilling derrick is removed and, if installed with this purpose in mind, can be moved with the drilling derrick and incorporated in the new foundations.

Often corner piers under each leg of the derrick will be all that is required. These piers must be carefully designed and constructed not only to give assurance that they are properly placed and of appropriate height, but also to attain a suitable spread of the concentrated load at the derrick corners over the subsoil, and to provide a mass sufficient to prevent overturn of the derrick under the horizontal forces that may become operative. It will be recalled that foundation bolts attach each leg of the derrick rigidly to its foundation pier. Good design practice dictates that the minimum dimensional requirements for proper load distribution should first be determined and then, if their weight is less than necessary to prevent overturning of the derrick by wind action and the horizontal thrust of a pipe setback, sufficient

additional concrete must be added to the piers to bring the total weight up to the necessary minimum.

TABLE XVI.—DIMENSIONS FOR DERRICK CORNER FOUNDATION PIERS*
(From A.P.I. Code of Recommended Field Practice, Rigs and Derricks)

Derrick No.	Derrick size	Top of pedestal A	Bottom of pedestal B	Height of pedestal C	Volume of concrete, cu. yd.
16	122′ × 24′	2′0″ sq.	8′9″ sq.	3′9″	4½
12	94′ × 24′	1′9″ sq.	7′9″ sq.	3′3″	3
11	87′ × 24′	1′9″ sq.	7′9″ sq.	3′3″	3
10	80′ × 20′	1′7″ sq.	7′0″ sq.	3′0″	2⅓
9	73′ × 20′	1′4″ sq.	5′7″ sq.	2′3″	1¼

* Soil-bearing capacity is here assumed to be 3,000 lb. per sq. ft. Letters at head of third, fourth and fifth columns refer to dimensions on sketch reproduced in Fig. 42.

Concrete derrick footings are of various forms, often reinforced with steel wire mesh to distribute the load over the entire area of the base and to offset the tendency of the pier upon which the derrick leg rests to "punch through" the slab at the base.

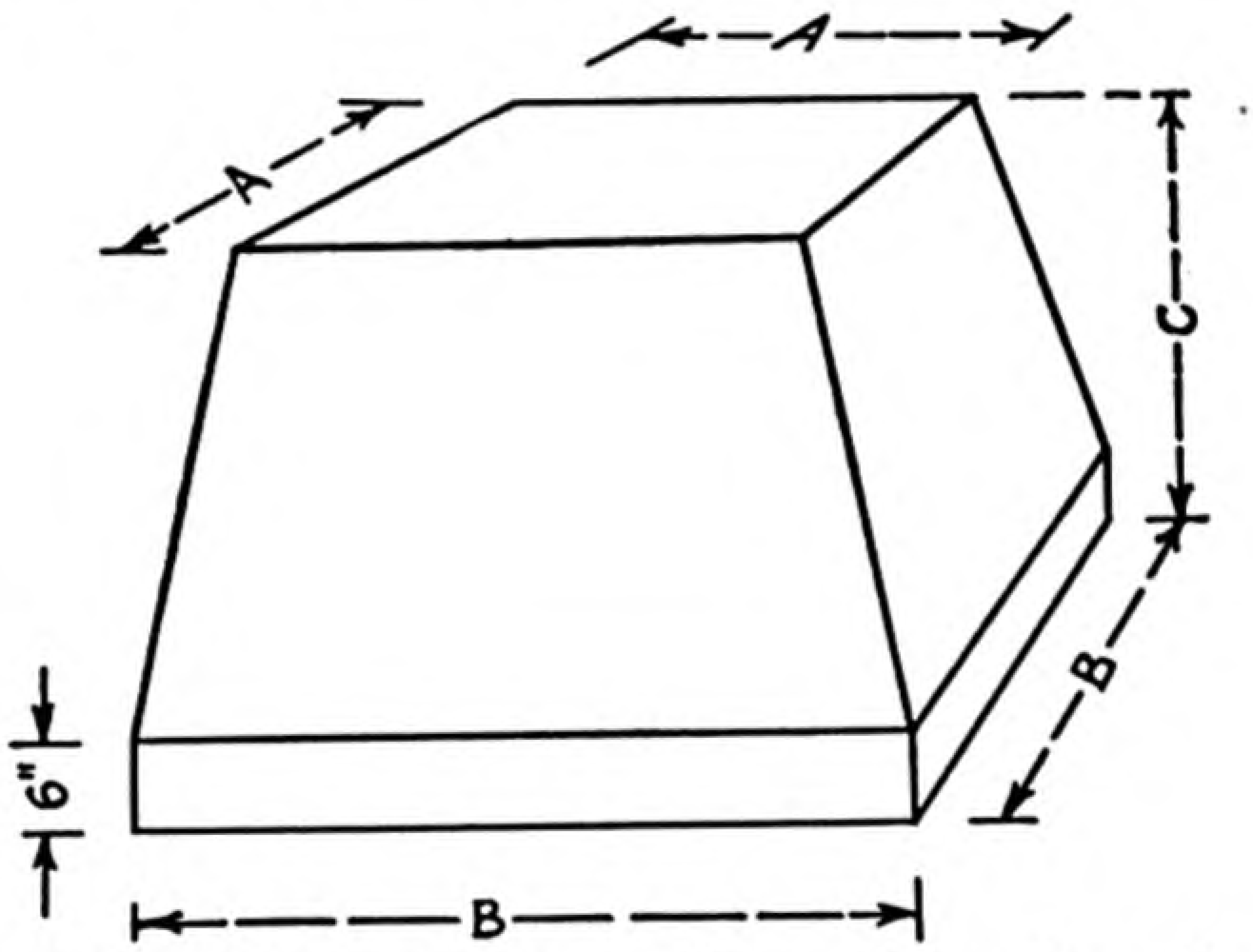


FIG. 42.—Derrick foundation pier. (Letters refer to dimensions given in Table XVI.)

The A.P.I. Committee on Standardization of Drilling Rigs and Derricks recommends the form of foundation pier sketched in Fig. 42. With reference to this, Table XVI gives recommended dimensions for derrick corner foundation piers and for the volume of concrete in each pier. These dimensions are based upon an assumed soil-bearing capacity of 3,000 lb. per sq. ft. and a 70-m.p.h. wind and standard drill-pipe setback as specified in Table XV. The following formula may be used for computing the height of concrete foundation corners:

$$\text{Height} = \frac{(\text{area of base} - \text{area of plate-bearing surface}) \times (\text{total load on corner})}{(4 \times \text{area of base}) \times (\sqrt{\text{area of plate-bearing surface}}) \times (\text{shearing strength of concrete})}$$

The shearing strength of massed concrete may be assumed to be 7,200 lb. per sq. ft.

Derrick Substructures.—With the purpose of standardizing rig foundations and reducing the investment in fixed supports, unitized steel substructures have been

devised and are available from derrick manufacturers. These substructures are so designed that they can readily be dismantled and moved in unitary fashion with the drilling rig from one location to another. They are adaptable to a wide variety of topography and soil conditions and in many cases can be erected directly on the natural ground surface without the necessity for providing elaborate timber or concrete supports. Inasmuch as they support the derrick well above the ground level, cellar excavations are often unnecessary or, if needed at all, may be shallow. However, each installation must be given individual study and a substructure of suitable type and design selected to meet the requirements imposed. Some are designed for use on level ground, some for hillsides, river banks, tidelands, marshlands, etc. Of course, in most cases the site must be graded or a certain amount of excavating must be done to provide a reasonably level and smooth bearing surface for the substructure. In marshy areas, a timber, concrete or steel mat must be provided, or piles must be driven to support the substructure. The substructure may be of timber, but steel is preferable. Though the first cost of the steel structure is greater, it resists decay and has longer life, it is stronger and provides a firmer foundation, and it presents less fire hazard than timber.

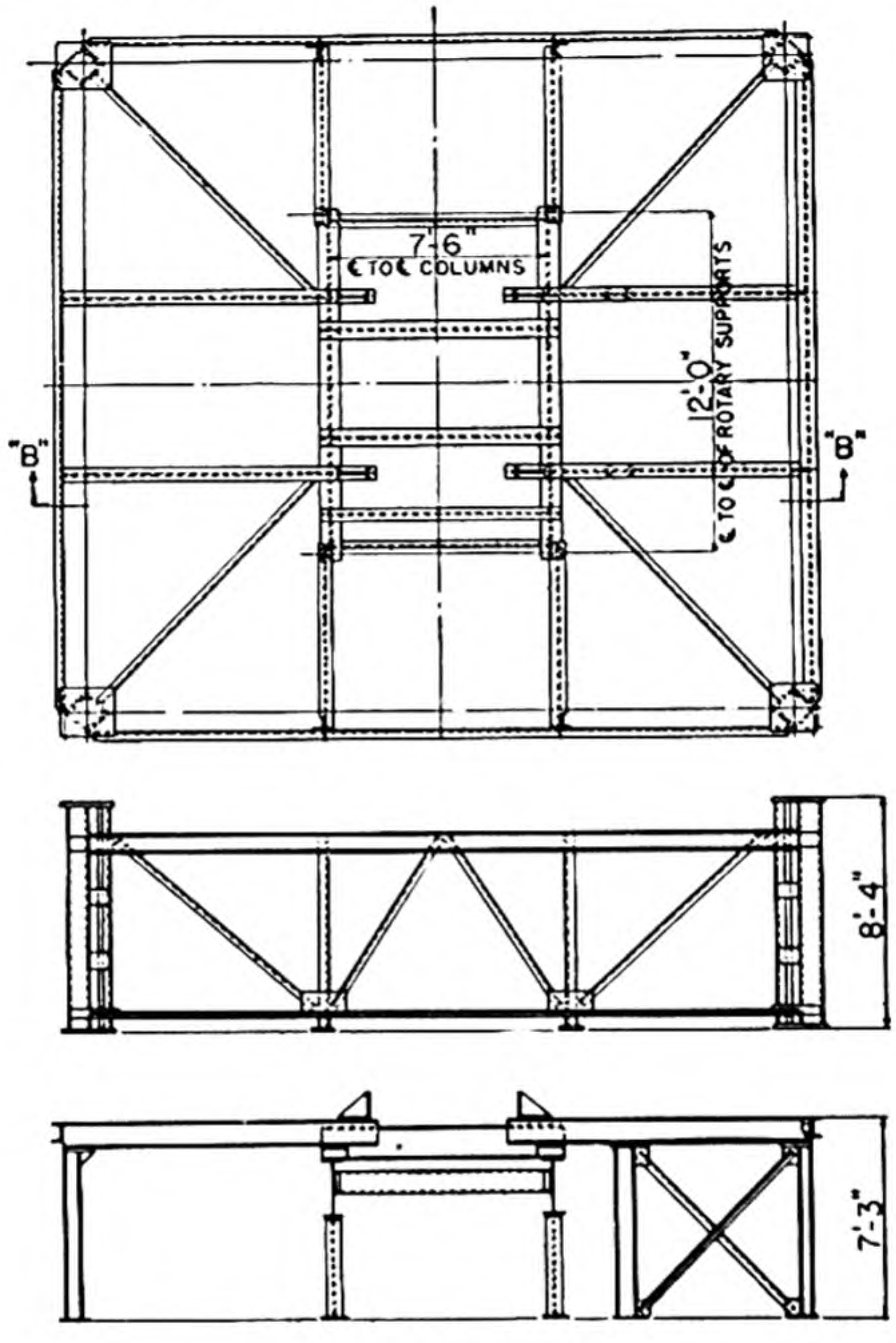
American Petroleum Institute standards recognize two types of steel substructures. The type *A* substructure is designed for use with six foundation piers, where soil conditions make it necessary, to carry the concentrated pipe setback and rotary table loads. The function of the piers is to prevent settling or caving around the cellar opening. With this type of substructure, the blowout preventer equipment is lowered through the derrick floor. The type *B* substructure is designed to carry the setback and rotary loads on four foundation piers, soil conditions permitting. This type is also used where there is a deep cellar, cellar ramp or stairway, making it possible to bring in blowout preventer equipment below the level of the derrick floor. Dimensions have been standardized for substructures designed for derricks of 24-, 26- and 30-ft. base squares. In each case, the height is 7 ft. 3 in. The substructure comprises two parts: the derrick supports, consisting of four corner posts with exterior bracing to support them in fixed positions, and the beams, posts and braces necessary to support the rotary table and pipe setback. The combined capacity of the four corner columns of the 26- and 30-ft. base substructures must be a minimum of 950,000 lb.; for the 24-ft. base substructure, a minimum capacity of 700,000 lb. is prescribed. The two larger sizes are designed to support 450,000 lb. of casing on the rotary table beams and 200,000 lb. of drill pipe on the setback beam. Figure 43 presents structural details of the A.P.I. type *A* substructure, designed for use on level ground.

Substructures designed to support the steam engine or other prime mover used for driving rotary rigs are also available. These customarily comprise a group of structural steel trusses with connecting braces, forming a rigid support of adequate strength to support the power plant, and so constructed that it can be skidded about as a unit. Usually it is of the same height as the derrick substructure, but in some arrangements of rotary equipment the power plant is at a lower elevation.

For use with derrick substructures on surface soils having low bearing resistance, steel "grillage" may be employed. Composed of a series of light steel beams, tied together with short posts and braces, it is designed particularly to be used in conjunction with timber or concrete mats to secure a suitable load distribution over a large surface of subsoil, with a minimum of timber and concrete. Steel grillage can be salvaged and moved to a new location with the drilling derrick and substructure after the well is completed.

Some operators pour a concrete pad several inches thick over the entire area beneath the derrick, with a shallow cellar lined with a thick concrete floor and walls monolithic with the surface pad. Metal eyebolts embedded in the concrete are

used to attach turnbuckle "hold-downs" for anchoring the derrick. Such a pad is useful as a working floor about the well after the drilling derrick is removed and a production derrick substituted. Adequate derrick footings, also monolithic with the surface pad, are built into the concrete to support the loads imposed on the grillage when long strings of heavy drill pipe and casing are being run. Instead of concrete piers under the derrick corners, an excavation is made at each derrick corner and is filled with water-tamped sand, upon which heavy timber mats are laid. Derrick leg foundations are of heavy crossed-steel beams resting on the timber mats.



SECTION "B-B"

(Courtesy of Lee C. Moore & Co., Inc.)

FIG. 43.—Structural details of A.P.I. type *A* derrick substructure.

Rig Foundations for Marsh Drilling Operations.—In many localities, wells must be drilled in marshy locations or on tidelands where soil conditions do not permit employment of the usual rig foundations. For such situations, special types of foundations have been developed which involve use of wooden mats and substructures, earth fills or piling. It is the objective of these devices to distribute subsoil loads within a range of 250 to 1,000 lb. per sq. ft., depending upon the character of terrain. Before the type of foundation to use in a given location is determined, a study of surface conditions should be made, perhaps including a physical test to determine the soil-bearing capacity, or a core-drilling test to determine the depth to a firm load-bearing stratum. Grass and grass roots in the surface soil aid materially in increasing its load-supporting capacity.

For surfaces capable of supporting 250 to 1,000 lb. per sq. ft., earth fill or wooden

mats may be employed. An earth fill is made by transporting materials such as stone, gravel, sand or shale to the location and spreading it over the site. The material gradually settles and becomes embedded until it is capable of supporting the derrick load, assuming that suitable footings are provided for spreading the concentrated loads over a large surface. Wooden mats are prepared by placing 3-in. plank, edge to edge or a few inches apart, over the entire area of the site. Two courses of plank are preferably used, one over the other, arranged with the plank in the upper course at right angles to that in the lower. A crisscross mat of this type may be constructed of 3- by 8-in. or 3- by 10-in. pine planks, spaced 4 or 6 in. apart in each course. Planks in the upper course are toenailed to those in the lower, to assure rigidity under load. A difficulty that has been experienced in some cases with timber mats in wet marshland is the tendency to form a depression or crater around the well, so that the weight of the drilling rig must be carried largely by the edge of the mat.

For less stable surfaces, resort must be had to piling driven to such depth as may be necessary to reach a more substantial subsoil. Piling foundations are often necessary in wet marshes or open-water tidelands. Such a foundation is constructed by driving a series of piles in clusters or groups in accordance with a design conforming with the loading pattern of the superstructure to be erected upon them. Piling may be driven to subsoil where their load-supporting capacity may be determined by formula or, if hardpan is not attainable within reasonable depth, dependence may be placed on the tendency of loose, wet silt to "freeze" to the piling and resist further displacement. Loading tests to determine the supporting capacity of the individual piles should be made in the latter case. After being driven to suitable depths, the tops of the piles are cut off to grade and capped with structural members forming the first course of the superstructure upon which the drilling rig rests. To assure long life, creosoted piles are sometimes used. Drilling rigs erected on piling are likely to vibrate excessively, though it is found that suitable cross bracing between piles and the use of interlocking caps to tie all piles together reduce this tendency materially. Tests indicate that individual piles may support from 15,000 to 35,000 lb., though if the destructive effects of vibration are to be avoided, lesser values should be assumed. Thus, as many as 12 piles may be used under a drilling-engine foundation, though the engine weighs only about 18,000 lb.

Marine Foundations for Drilling Rigs.—In some localities, well locations are at offshore situations along seacoasts, in lakes or inland waterways. Such situations are found along the Gulf Coast of Louisiana, the Pacific Coast of Southern California, in Lake Maracaibo, Venezuela, the Caspian Sea in southern Russia, and other regions. In Lake Maracaibo, some well locations are nearly 8 miles offshore in 60 ft. of water. In the Elwood field of California, some locations are 2,100 ft. offshore, in 45 ft. of water, exposed to open-sea conditions. In such situations, rig foundations may be provided by constructing "artificial islands" in the form of cofferdams, or dependence may be placed on piling driven to substantial subsoil below the ocean or lake bottom. For convenient access, these structures may be incorporated in a framework of piers extending outward from shore, though in some cases they are so far from shore that they may be reached only by motor boat or seaplane.

In the Elwood field of California, piers constructed of steel piling and braces supporting a timber deck extend straight out from shore, each pier providing a roadway over which motor trucks may deliver equipment and materials to rig locations at about 356-ft. intervals, immediately adjacent to the piers. The rigs rest on reinforced concrete caissons extending through sea-bottom sediments to a hard shale subsoil, in some instances as much as 112 ft. below the derrick floor. Several types of supporting structures have been developed. For the shallower locations, five

caissons are employed: one 8-ft. steel caisson filled with reinforced concrete under each corner of the derrick and a 14-ft. caisson of similar construction beneath the center of the rig, enclosing the conductor casing. The cylindrical caissons are formed of interlocking steel piling, driven into hard shale and subsoil. The interior of each is then excavated to the shale surface and a number of H-section steel piles driven into the shale within the steel shell. The remaining space is then filled with concrete.

For deep-water conditions, where swaying in response to wave action is troublesome, the Collins single-leg stabilized foundation was developed. This consists of three members: a single, large central caisson, 19 ft. in diameter, surrounded by a stabilizer of concrete, 40 ft. in diameter and 10 ft. deep, and a reinforced concrete derrick base, 26 ft. square and 4 ft. thick on top of the 19-ft. caisson. An ample cellar, 12 ft. in diameter and 17 ft. deep, is formed in the concrete caisson below the derrick floor, with a side entrance on the shoreward side. In the Elwood field, most drilling operations were conducted with power furnished by electric motors, so that no provision was necessary for heavy, bulky steam equipment. Reserve drilling fluid was stored in on-shore tankage and pumped to the drilling rigs through pipe lines extending along the piers.[19,20,23]

Some rig foundations in the Elwood field are on cofferdams constructed by driving interlocking sheet-steel piling around the area and then filling space within the cofferdam with sand or broken rock. Seams are calked with oakum and quick-setting cement. Steel hoops surround the piling and cross members of structural steel help to support the piling against internal pressure. A riprap of broken rock may also be deposited on the ocean floor around the outside of the structure. Some cofferdams are rectangular, 65 by 40 ft. in size. Others are circular, 36 ft. in diameter. Heavy steel H bars, driven into the underlying shale beneath the cofferdam, support the derrick and drilling equipment. A cellar is excavated within the fill and lined with concrete, cast integrally with a heavy concrete mat over the remaining surface of the cofferdam.

In its drilling operations in Lake Maracaibo, Venezuela, the Lago Petroleum Corporation has used both solid reinforced concrete piles and caisson-type piles to support steam-powered drilling rigs.[26,27] Drilling engines are supported by the piling on a cantilever extension of the derrick floor, but the steam boilers, mud pumps, mud storage facilities, casing rack, etc., are mounted on a floating barge that can be moved about from rig to rig as required. In earlier operations, solid reinforced concrete piles were used, 16, 20 or 24 in. square, and as much as 133 ft. long. Three piles support each corner of the derrick, two driven vertically and one at an angle of 30 deg. from the vertical. These piles are capped with heavy blocks of reinforced concrete upon which a 24-ft. square structural steel derrick base is erected. Caisson-type hollow piles, used in later operations, one under each derrick corner, are 60 in. in diameter, precast in 15-ft. sections and assembled by welding joints together in whatever lengths individual locations may require. Each section consists of a steel cylinder encased in a 5-in. sheath of concrete strengthened by spiral steel reinforcement. The lower end of each hollow pile is equipped with an inverted, cone-shaped concrete shoe, 5 ft. in length. This aids it in penetrating the accumulated sediments on the lake bed. The hollow pile is not driven but is supported in vertical position and spudded into the looser surface material, then loaded with a dead weight of 200 tons, under the influence of which it sinks further into the lake-bottom sediments. During drilling operations, the load on each pile does not exceed 100 tons. Tops of the caisson piles are connected with steel-arch plate girders, clamped to the piles by steel sleeves, and on these girders the derrick and substructure are erected.

Drilling Barges.—For use in inundated areas, the derrick and drilling equipment may be mounted permanently on a floating barge that is moved as a unit from one

location to another. Drilling barges have been used successfully along the Gulf Coast of the United States, both at open-water offshore locations and on inland bayous. In some cases, they are moved about in marshy areas through specially excavated canals. A common arrangement involves mounting the derrick and drilling machinery on one barge and a boiler plant or diesel-electric power plant on another. Casing, cement and special service equipment may be floated to the drilling barge on smaller barges. When rigged for drilling, the barges are anchored to a few piles driven in such a way as to hold them stationary while drilling is in progress.

One highly successful type of drilling barge, designed for shallow-water situations, is submersible. It is floated to location and then steel compartments within the vessel are filled with water so that it sinks and rests on bottom while drilling is in progress. After the well is drilled, the water compartments are pumped out, so that the barge is again floated. It can then be towed to a new location. Important economies may be realized through the use of this type of equipment, inasmuch as no time is lost in tearing down or rigging up the derrick and drilling machinery. The submersible barge is a patented device, patent rights being controlled by the Texaco Development Corporation. It provides much greater stability than is possible with floating equipment and is not seriously affected by tides, wind or waves when resting on bottom. If the underwater surface is irregular, the barge may be trimmed by pumping water into or out of the several compartments, so that the derrick is at all times vertical. The working floor of the barge remains at a constant level while drilling is in progress, and its position is uninfluenced by stacking drill pipe in the derrick or by varying the amount of drilling fluid stored in the space reserved for this purpose.

A preferred form of submersible barge, designed for drilling in water less than 10 ft. deep, really comprises two separate barges, each 120 ft. long and 24 ft. wide, arranged side by side, 8 ft. apart and held together by a superstructure. The barges are rigidly constructed of $\frac{5}{16}$- and $\frac{3}{8}$-in. steel plate, tied together with two 33-in. girder beams and longitudinal trusses. Copper-bearing steel is used to reduce corrosion. Each barge incorporates eight watertight compartments, which permit differential flooding with or withdrawal of water to facilitate level settling and control in floating. Two legs of the derrick are supported on the upper deck of each barge and there is a clearance of 7 ft. 4 in. between the derrick sills and the bottoms of the barges.[25]

In preparing for barge drilling, piles are driven around the location, suitably braced, and the barge is floated into position and anchored to the piles before sinking. The well is drilled in the 8-ft. space between the two parts of the barge, so that when it is completed, the barge structure may be backed away, leaving only the well casing and control valve projecting above the water surface. A production derrick is then erected over the well on pile supports. Only 36 hr. is necessary to float and move the barge from one location to another and drilling at the new location may be started at once.

A barge of the type described costs approximately $30,000 to construct. A royalty of $15,000 per barge is charged by the patentee for use of the submersible feature. Floating boiler barges, carrying four boilers, have hulls 28 ft. wide, 84 ft. long and 7 ft. deep, with a superstructure 8 ft. high, and cost about $9,000. They have storage space for 1,000 bbl. of water.

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CHAPTER V

CHURN DRILLING EQUIPMENT AND METHODS

The principal features of the churn drilling methods and the most used representative of this group, the American standard cable system, were described in Chap. IV. The present chapter will be devoted for the most part to a more detailed description of the component parts of the American standard cable drilling rig, to a consideration of their functions and relationships, their manipulation and control in the routine of drilling and the results secured through the use of this system of drilling.

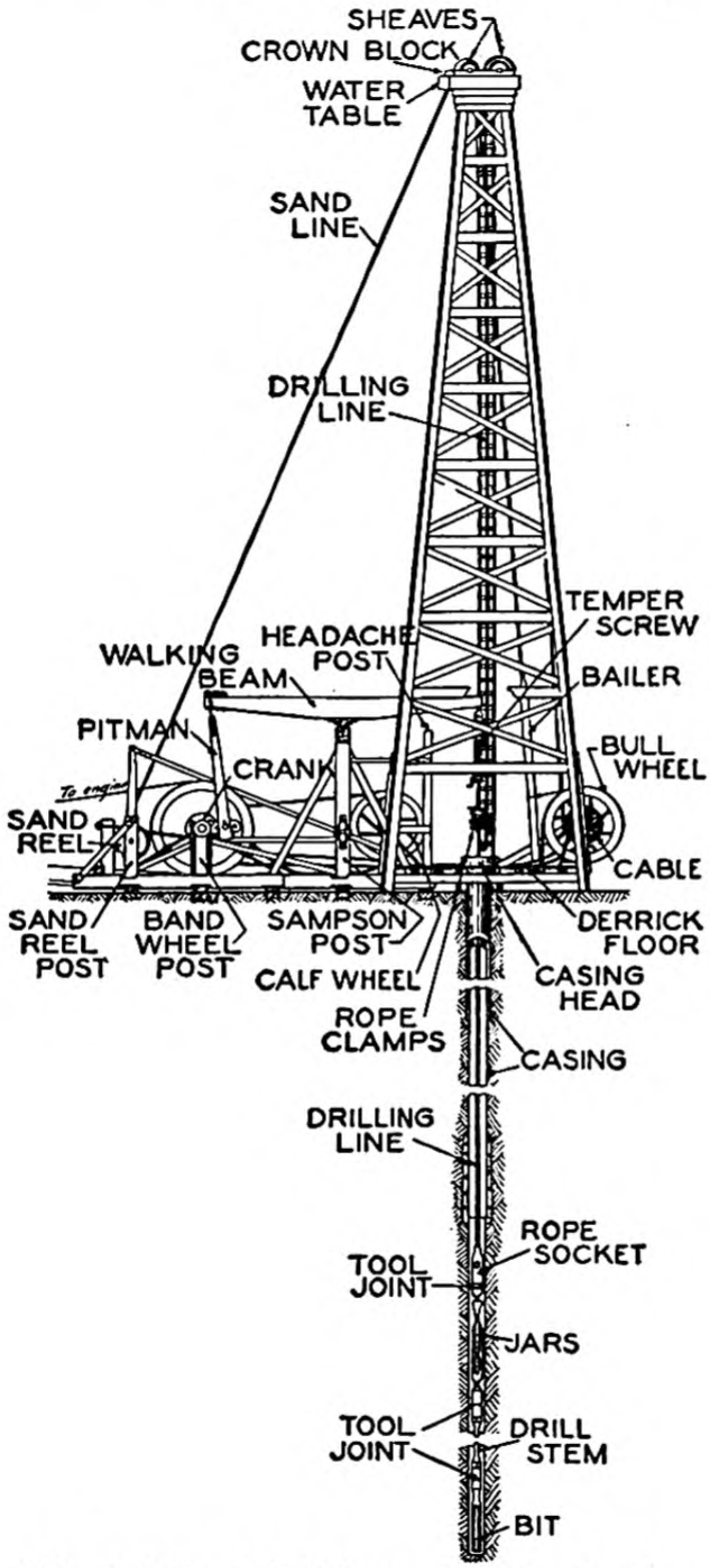
THE AMERICAN STANDARD CABLE DRILLING RIG

The usual arrangement of the various parts of the American standard cable drilling rig is represented in Fig. 24, page 110. Structural details of the derricks necessary in this as well as other systems of drilling are explained and illustrated on pages 122 to 153. We may broadly classify the remaining parts of the cable drilling rig under four headings. The power plant is often a single, horizontal-cylinder steam engine, though electric motors and internal-combustion engines are also used in cable drilling. The rig wheels, including the band wheel, the bull wheels, the calf wheel, sand reel and crown block, are important parts of the rig that warrant detailed description. The character of cables and cordage used for various purposes will be an important consideration. Lastly, the tools used in drilling by the cable method will be described in detail. Figure 44 will serve to indicate the relationship between the several parts of the American standard cable rig.

Power Plant for Cable Drilling

Most cable drillers prefer to use a steam engine as a source of power because of its superior flexibility. In most oil fields, too, there is an abundance of cheap fuel in the form of either natural gas or oil, so that steam power can be cheaply developed. The boiler plant is usually erected near the well so that it may be under the immediate control of the driller and his assistant, the "tool dresser," at all times. The tool dresser has occasional periods of freedom from operations in the rig, when he can give the boilers such attention as they require. Most cable drillers are familiar with steam equipment and are capable of making all necessary adjustments and replacements of engine and boiler parts.

For drilling with the American standard cable rig, it is customary to provide two boilers of from 30 to 70 rated horsepower, the actual power obtainable from them being somewhat greater than the rated horsepower.



(*After J. E. Brantly in "Elements of the Petroleum Industry," courtesy of Am. Inst. Mining Met. Eng.*)

FIG. 44.—General features of the American standard cable drilling rig.

The return-tubular type of boiler, illustrated in Fig. 71, is probably the most commonly used, though the locomotive type (Fig. 70), which requires but little in the way of masonry supports and is readily portable, is also popular. The latter style is occasionally mounted on wheels to

facilitate transportation. Additional details concerning the several types of boilers used in supplying steam power for drilling purposes will be found in Chap. VI, pages 205 to 211. Working pressures of 100 to 175 lb. per sq. in. are usual. The steam consumption of a standard cable drilling rig, working at a depth of 2,800 ft. with 8-in. tools, ranges between 55 and 140 boiler hp., the latter figure being approached only occasionally for short periods of time in drawing out the tools. Drilling on the beam consumes the minimum amount of power, and bailing operations require approximately 75 hp.

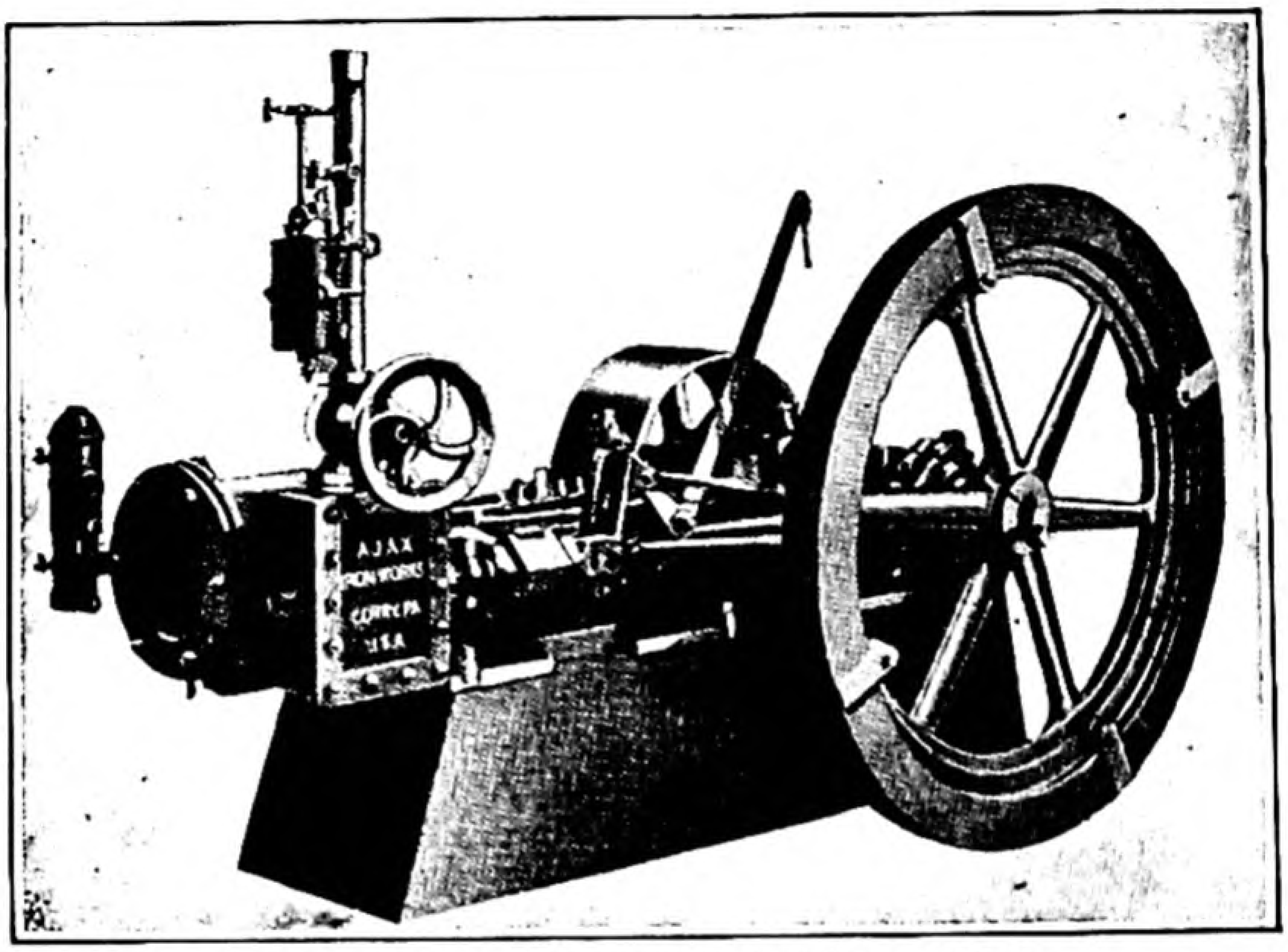


FIG. 45.—"Ajax" steam drilling engine.

Steam engines used for cable drilling are usually of the simple, single-cylinder, reversible, slide-valve type of from 15 to 50 hp. Simplicity, flexibility and accessibility for repairs are matters of prime importance in the selection of an engine to meet the variable load requirements imposed. The type of engine generally used in cable drilling practice has a cylinder 12 in. in diameter, a piston stroke of 12 in., and when operated under a steam pressure of 100 lb. per sq. in. develops about 30 hp. For lighter service in the drilling of shallow wells, an 11- by 12-in. (25-hp.) or even a 9- by 12-in. (15-hp.) engine may be used. Figure 45 illustrates a well-known oil-country engine of this type. Under the most favorable conditions the steam consumption of such engines, operating at full load with 100 to 125 lb. steam pressure, ranges from 30 to 40 lb. of steam per horsepower-hour. However, this figure may increase to as much as 100 lb. for average operating conditions.

The steam supply to the engine is regulated by a throttle controlled from the headache post by a telegraph cord and handwheel. A simple reversing link on the eccentrics, operated by a lever and rod from the

headache post, enables the driller to control the direction of rotation of the driving pulley. A heavy flywheel, to which additional weight in the form of extra balance rims may be clamped, serves to equalize the loads on the engine. Special lubricating devices, boiler feed-water pumps and heaters are often a part of the drilling equipment.

Electric motors have been successfully adapted to the work of cable drilling, though drillers are often reluctant to make use of electric power because of their greater familiarity with steam power.

For cable drilling purposes, an ordinary variable-speed, reversible, slip-ring induction motor with wound rotor gives best results. Speed control is effected through the introduction of a suitable resistance in the rotor circuit, adjusted by a controller. One successful type of drilling motor is equipped with an auxiliary controller in addition to the main controller, to give the finer speed adjustments necessary in adapting the movement of the walking beam to the period of vibration of the drilling cable. The main controller alone gives 10 points of speed control; the auxiliary controller cuts in 8 additional points between any adjacent points on the main controller. This gives 88 different speeds. The two controllers are located near the motor but are operated independently by telegraph cords from the headache post.

In cable drilling, the beam must overspeed on the down stroke, permitting a free drop of the drilling tools to strike the most effective blow. The motor therefore must slow down on the upstroke and overspeed on the downstroke. This is accomplished by introducing a secondary resistance in circuit when the motor is operated at proper speed.

An ammeter placed in the motor circuit is not only useful in indicating the power consumption during different phases of the work but serves also as an indication of the amount of strain placed upon the motor and derrick equipment. A recording ammeter is useful also as a check on the efficiency of the drilling crew and, to one skilled in interpreting the records obtained, provides an independent record of the operations in progress and the percentage of time devoted to different operations during each "tour."

For the standard sizes of cable-tool and rotary rigs, a 75-hp. drilling motor has sufficient capacity for the deepest wells now drilled. For shallower wells, say, less than 2,000 ft. in depth, a 50-hp. motor is sufficient in many cases. In some foreign fields using other types of rigs, motors as large as 150 hp. have been used. Drilling motors can exert a very high pulling torque, and their ability to do so in an emergency is often important. The motor increases its pull automatically as the load increases, without any changes or adjustments, and develops its maximum pull at dead stall.

Wherever natural gas is available, the internal-combustion engine offers an economical solution of the power problem. In early efforts to adapt the gas engine to cable drilling service, use was made of the horizontal, single-cylinder type of engine. This engine, however, was found to be poorly adapted to the requirements of drilling because of its lack of flexibility in speed and power output. The failure of this type of engine in operating drilling equipment seems to have prejudiced operators against all types of gas engines for this purpose, but more recent tests with vertical four-cylinder engines indicate that the larger sizes of multicylinder engines are capable of operating churn drilling equipment in a satisfactory manner and at considerably less cost than is possible with the less efficient steam engine. The greater success of the multicylinder engine in comparison with the single-cylinder type is due primarily to its greater power and speed flexibility. Diesel engines, though adaptable to rotary drilling, are not so adaptable to cable drilling because of their lack of flexibility.

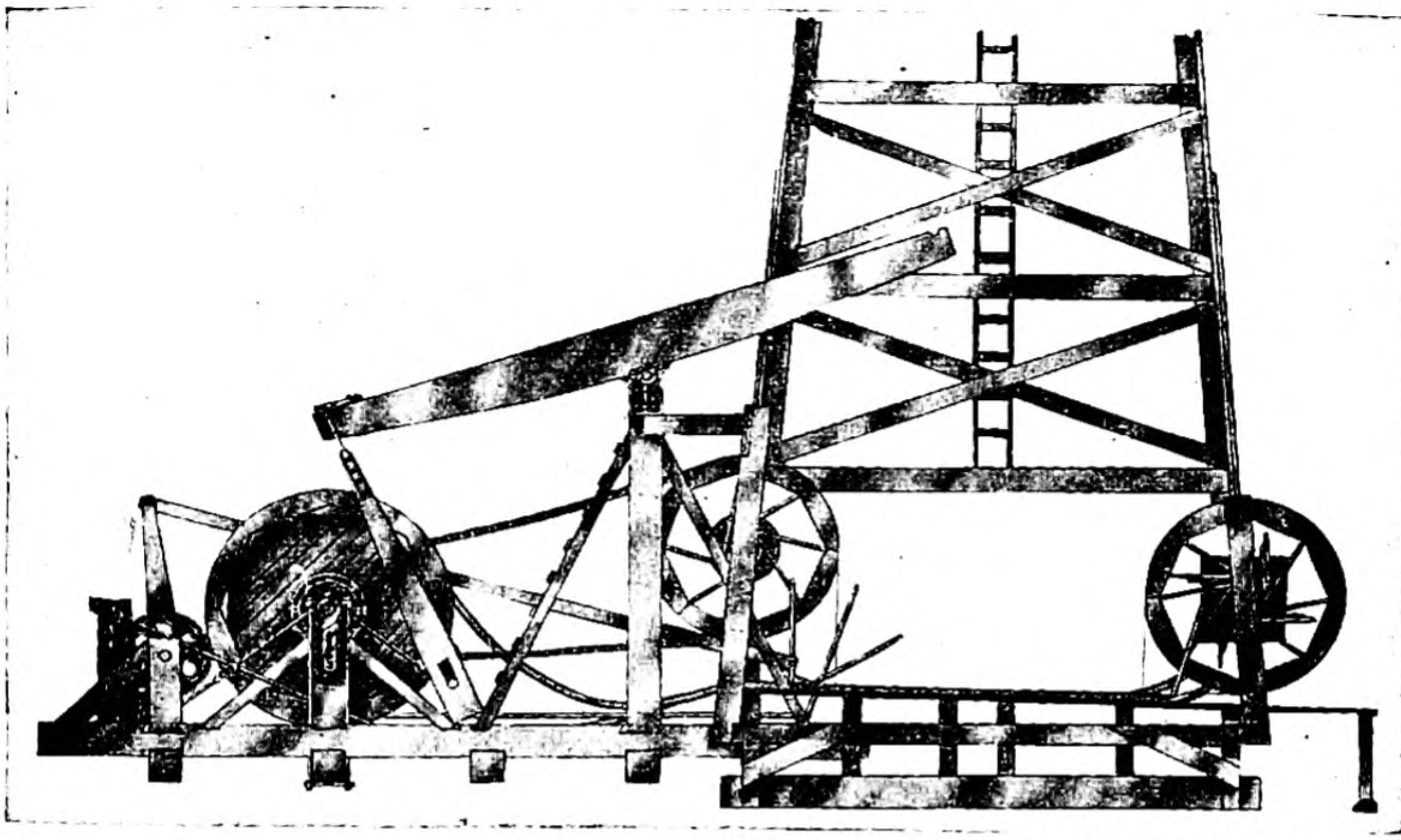
The type of internal-combustion engine that has been found most successful in operating cable drilling equipment is modeled closely after the four-cylinder automotive engine, except that it is of higher power and is equipped with a special reversing drum and clutch, a flywheel and, sometimes, an auxiliary starting engine. The automotive type of gas engine, illustrated in Fig. 74, develops 120 hp. Constant speeds and power output can be maintained at from 85 to 500 r.p.m. It may operate on natural gas, gasoline or distillate. The chief advantage of the internal-combustion engine for drilling purposes lies in its economy. The gas engine requires about one-tenth of the fuel by weight that an oil-burning boiler requires and comparatively little water. It would appear to be particularly useful in drilling wildcat wells where fuel and water are large expense items.

The Rig Wheels

The large wheels which provide braking surfaces and a means of applying power in the various operations of hoisting and lowering the tools, casing and the bailer are usually built of wooden segments, cants and arms, rigidly nailed or bolted together. They are bolted to cast-iron gudgeons which provide a means of fastening them to the wooden or metal shafts on which they revolve.

The band wheel is a solid wooden wheel varying from 9 to 12 ft. in diameter, built of lumber segments held together by numerous bolts. The wheel has a smooth face, 12 in. wide, on which bear the belt from the engine pulley and the sand-reel friction pulley. The wheel is bolted at the center to two cast-iron hubs, one on either side, which provide a means of keying the wheel to the crankshaft on which it turns. Attached

to one side of the band wheel is a wooden tug pulley 7 ft. in diameter, on the rim of which one or two grooves are cut to receive the bull rope or



(*Courtesy of National Supply Co.*)

FIG. 46.—Side elevation of standard cable rig showing sand reel, band wheel, crank, pitman, walking beam, calf and bull wheels and various rig posts and sills.

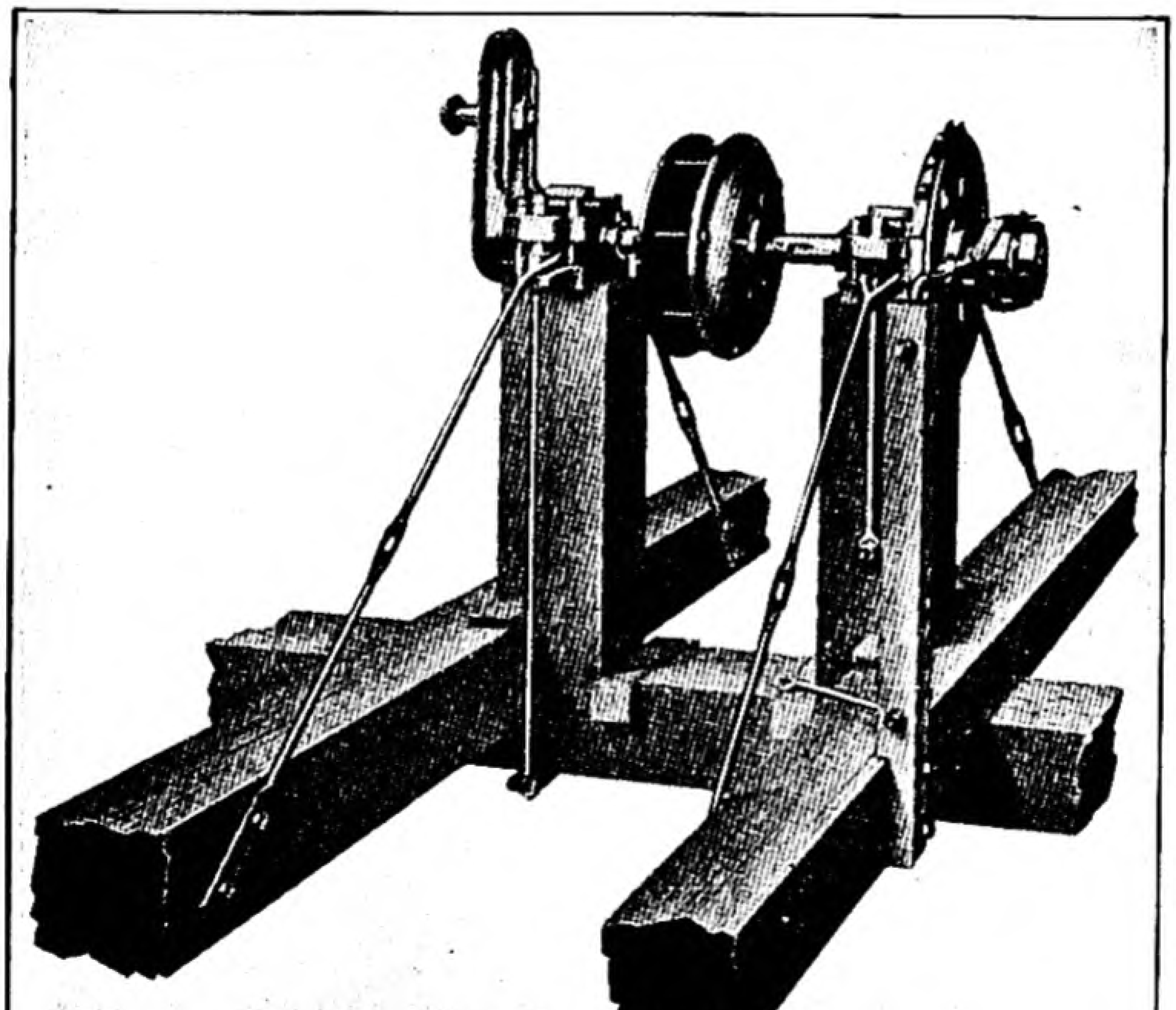


FIG. 47.—Showing assembly of crank, wrist pin, crankshaft, band-wheel gudgeons, sprocket, clutch, braces and supporting posts and sills.

ropes which drive the bull wheels. The steel crankshaft is supported by two metal bearings, one on either side of the wheel, mounted on two upright jack posts (see Figs. 46 and 47).

The bull wheels, two in number, are mounted, one on each end of an oak shaft 14 or 15 ft. long and 16 or 18 in. in diameter. Sometimes a shaft of smaller diameter made of steel pipe is used. The wheels are $7\frac{1}{2}$ or 8 ft. in diameter, built of oak cants and arms. The wheels are from 9 to 12 in. wide, one faced to a smooth braking surface for a metal band brake which bears upon it, and the other grooved to receive the drive from the bull rope or ropes. The bull-wheel shaft, when built of wood, is round in the center but is usually octagonal at the ends in order to provide a positive grip for the metal gudgeons that serve as the hubs

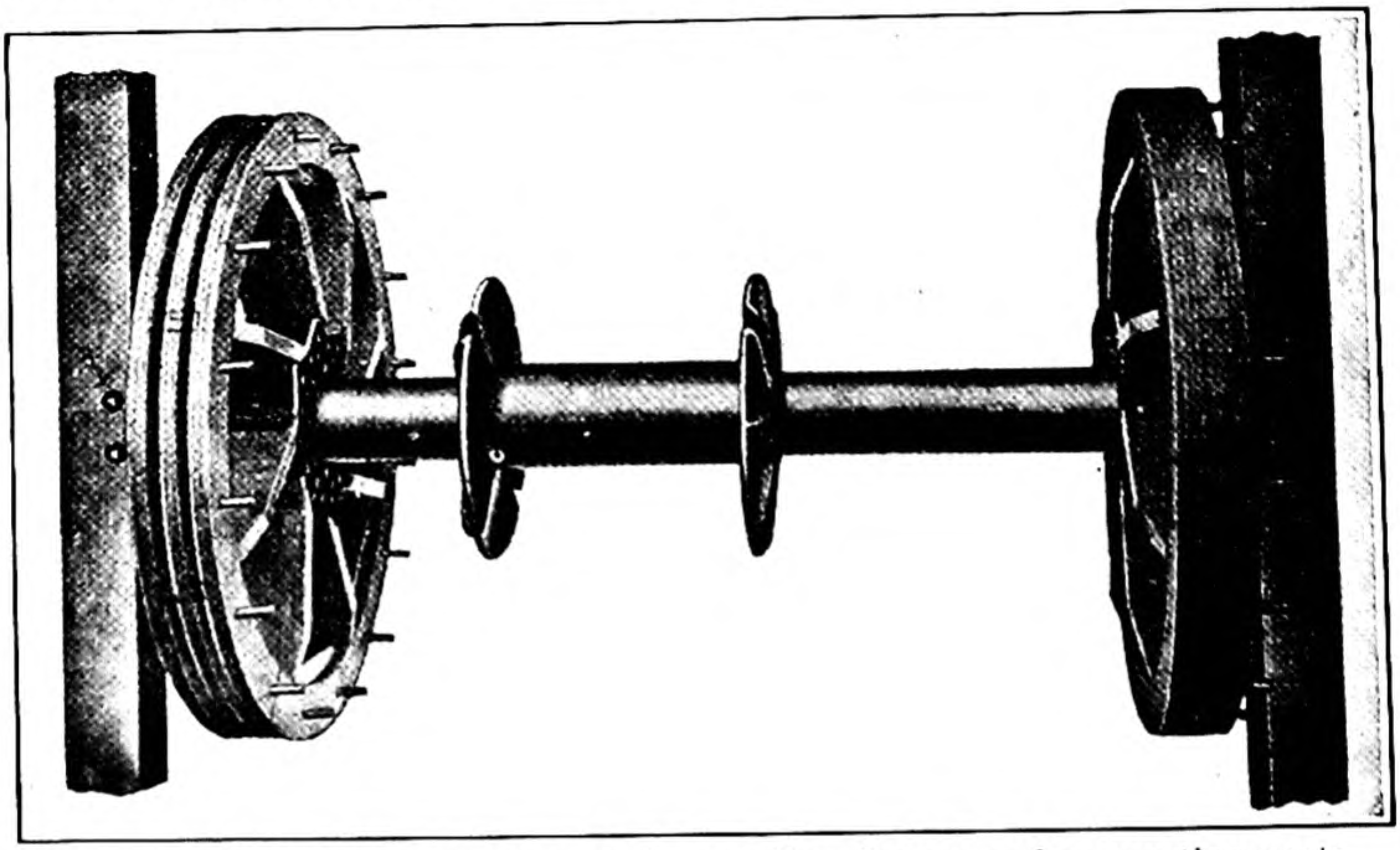


Fig. 48.—Bull wheels showing shaft, spooling flanges and supporting posts.

of the wheels, to which the arms or spokes are bolted (see Fig. 48). The metal gudgeons at the ends of the bull-wheel shaft are supported in metal boxes, mounted on substantial wooden bull-wheel posts, braced between the derrick sills and the first horizontal girt. Around the side of each bull wheel 16 wooden handles are inserted. These are useful in turning the wheels by hand when necessary in taking up slack in the drilling cable. Mounted on the bull-wheel shaft are two adjustable "spooling flanges" which prevent the drilling cable from slipping on the shaft and confine the portion of the cable in actual use to the central section.

The calf wheel is usually built more substantially than the bull wheels because of the greater strain to which it is subjected, but it is similarly constructed of oak cants and arms. Heavy calf wheels have twice as many arms as the ordinary bull wheel, the arms being braced in pairs in opposite directions (see Fig. 49). The calf-wheel shaft is similar in its construction and equipment to the bull-wheel shaft described in the preceding paragraph, except that it is shorter. It is supported by a pair of heavy upright posts and turns on steel gudgeons resting in metal

boxes. Mounted on one side of the calf-wheel rim is the sprocket wheel which receives the chain drive from the crankshaft sprocket. An earlier type of calf wheel using a rope drive instead of the chain drive is now almost obsolete. Frequently, the steel surface of the calf-wheel shaft is lagged with hemp rope to prevent abrasion of the casing line wound on it. A steel band brake operated by a lever bears on the wooden face of the calf wheel and prevents it from turning when it is required to support heavy loads.

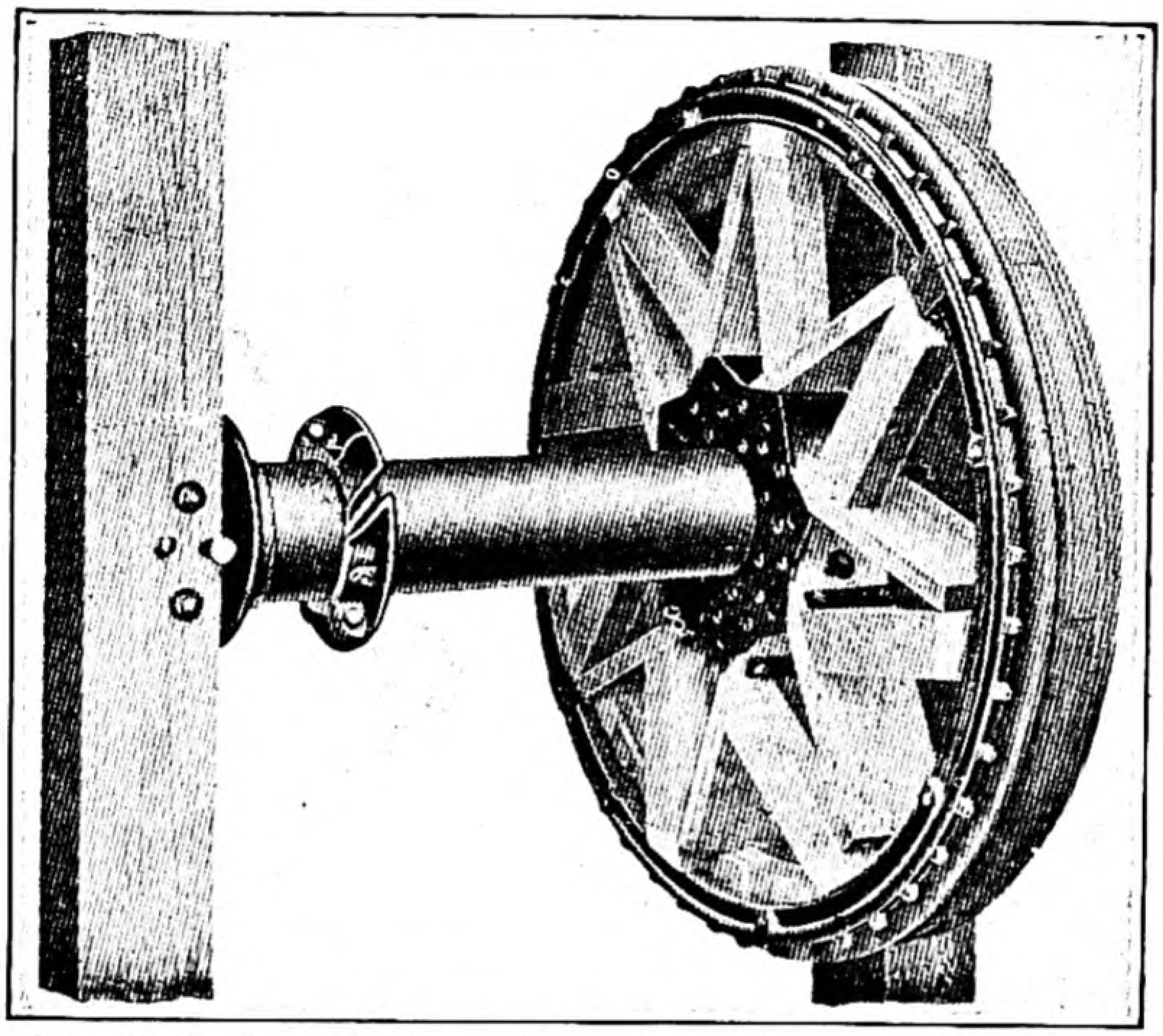


FIG. 49.—Calf wheel showing shaft, sprocket and supporting posts.

The sand reel is an all-metal drum, keyed to a steel shaft to which is also attached a cast-iron friction pulley (see Fig. 46). The sand line is wound on the drum. The friction pulley may be brought to bear against the face of the band wheel, causing the sand-reel shaft and drum to revolve. The drum is usually about 3 ft. long and varies from 6 to 20 in. in diameter. The drum flanges are often about 3 ft., and the friction pulley about 40 in. in diameter. The sand-reel shaft is supported by metal bearings mounted on a movable timber frame pivoted at its lower end on two heavy sand-reel posts. This frame may be drawn forward by the "sand-reel lever" until the friction pulley bears against the revolving band wheel, or it may be forced backward against a wooden post which bears against the friction pulley, serving as a brake to control the descent of the bailer. An improved type of sand reel is driven by a chain from a sprocket on the crankshaft. A chain-driven sand reel provides a more positive power connection for operation of the bailer, which is especially desirable in deep-drilling operations where the loads to be handled are often excessive for the friction type of drive.

The crown block contains 6 or 7 cast-iron pulleys ranging from 24 to 36 in. in diameter, supported by metal boxes, bolted to substantial oak or steel supports (see Fig. 50). These sheaves should be of large diameter in order to avoid sharp bends in the cables passing over them. The largest sheave, usually 36 in. in diameter, is the "crown pulley," over which the drilling cable passes. The "sand-line pulley" is of intermediate size, often 30 in. in diameter. The four (sometimes five) smaller sheaves are provided for the support of the casing line, which is threaded back and forth between them and the sheaves in the hoisting block. The number

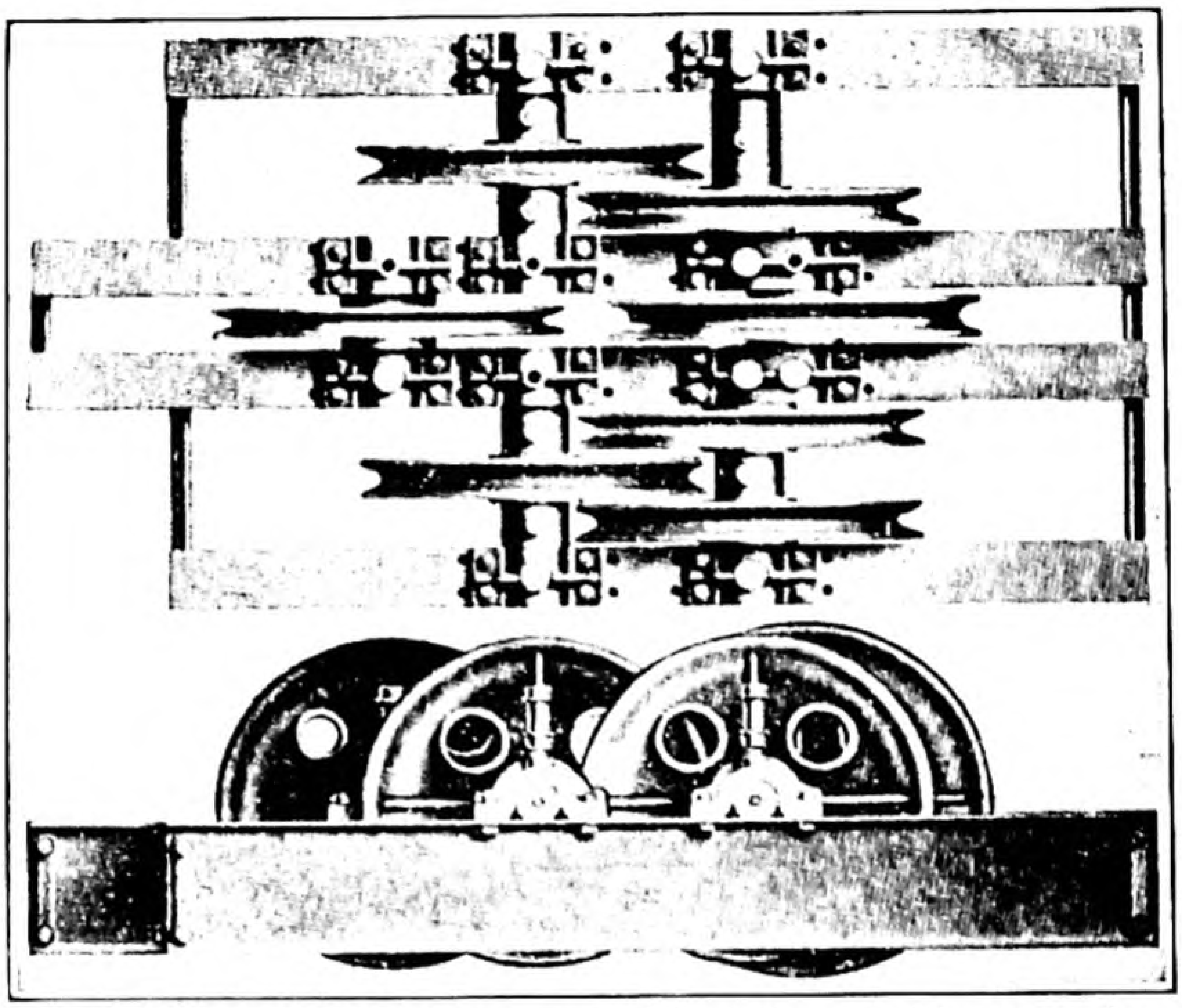


FIG. 50. Seven-sheave crown block for combination rig.

of sheaves provided for the casing line depends upon the load likely to be imposed, the mechanical advantage in favor of the power being in direct ratio to the number of ropes extending between the crown block and the hoisting block.

The Rig Irons.—All the metal parts used in the construction of the standard cable rig, with the exception of the nails, bolts, sand reel and guy wires, are known collectively as the "rig irons." They include such items as the gudgeons, shafts and boxes of the wheels, the crank and wrist pin, the sprocket wheels, chain and clutch, a metal stirrup for the pitman, the center irons or metal bearing on which the walking beam oscillates, together with numerous bolts and fastenings. Rig irons are furnished in complete sets by the manufacturers, varying in size and weight with the size of the rig for which they are intended. The size is designated by the diameter of the crankshaft, which may vary from 4 to 7½ in. Rig irons of the 4- and 5-in. sizes are used only for shallow wells and light work, the 6-in. size being commonly employed for heavier duty.

Aside from differences in size and weight, there is some variation in design of rig irons and in the list of parts furnished in sets. Thus, the California pattern, Oklahoma pattern and Pennsylvania pattern rig irons differ from each other in certain respects, being designed particularly for the type of rigs favored in the regions after which they are named.

The American Petroleum Institute has adopted standard specifications for rig irons in which working dimensions for all parts are prescribed. This is designed to facilitate interchangeability of parts and to permit the products of one manufacturer to be used in the same rig with those of another.

Cables and Cordage

The selection of material for the cables and ropes used in driving the wheels, operating the drilling tools and bailer and supporting the casing must receive careful attention. Either hemp, manila sisal or steel wire is used in the construction of these cables, and special forms have been devised to adapt them better to the purposes for which they are used.

The Drilling Cable.—Probably the most important of the cables used in the standard rig is the drilling cable which serves to connect the drilling tools in the well with the power at the surface. When drilling is in progress, the drilling cable is suspended from the walking beam to which it is attached by the temper screw. The surplus cable is carried up through the derrick over the large central crown pulley and thence down to the bull-wheel shaft on which it is coiled. When the drilling tools are being lowered or hoisted, or are suspended in the derrick, the tension in the drilling cable is transferred directly to the bull wheels and crown pulley.

The duty imposed on the drilling cable is severe. Not only must it support the weight of the tools (often between 1 and 2 tons), but the dead weight of the cable itself may be as great as that of the tools when operating at a depth of 2,000 or 3,000 ft. Furthermore, the strain imposed by the alternate application and relief of tension with each stroke of the tools and the wear resulting from rubbing of the outer strands of the cable on the rough rock walls of the well and the metal casing tend to weaken it and to shorten its useful life.

Hemp Drilling Cables.—Both manila fiber and steel wire have been widely used in the construction of drilling cables, but the former is generally preferred where its strength is adequate on account of its greater elasticity. With proper adjustment of the temper screw and motion of the walking beam, a much harder blow may be struck with the tools when they are suspended on a hemp cable than is possible with steel, because of the greater elasticity of the hemp cable, which materially increases the length of stroke. Furthermore, if the temper screw is adjusted so that the tools strike bottom on the "spring" of the line, they rebound quickly when the blow has been struck, thus dislodging the bit from the cuttings which otherwise tend to

hold it. The hemp cable imposes less strain on the derrick and makes hole faster than does the steel cable.

Hemp cables of 2, $2\frac{1}{4}$ and $2\frac{1}{2}$ in. diameter have been widely used in the drilling of wells up to 1,500 or 2,000 ft. in depth, but at greater depths the large-sized cable necessary becomes expensive and impracticable and a steel cable must be substituted. During drilling operations the well must be at least partly filled with water, and the friction developed by the motion of a rough manila cable of large diameter, through this water, seriously reduces the force of the blow struck by the tools and increases the power consumption. The displacement of fluid in the well by so large

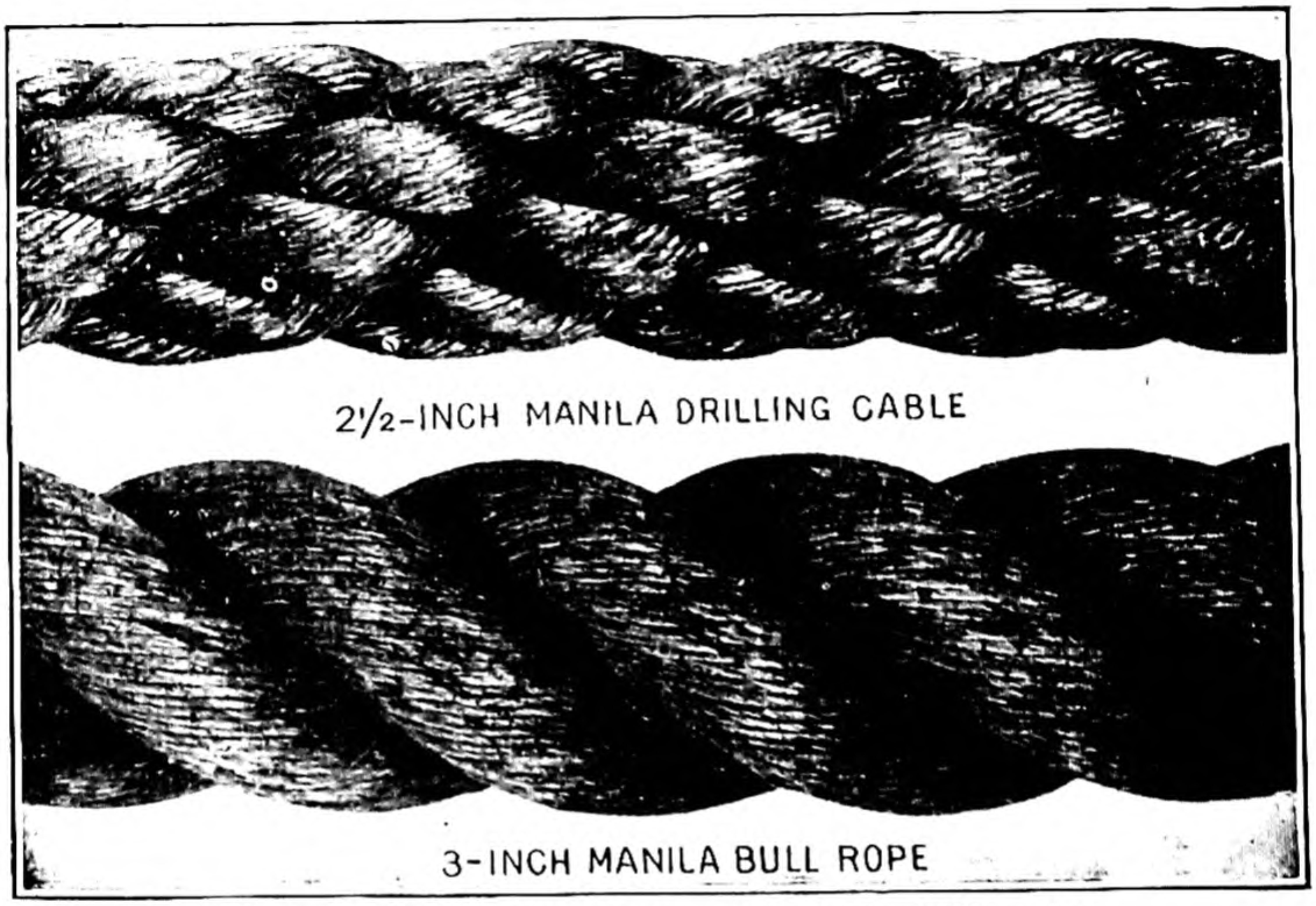


FIG. 51.—Types of cordage used in cable drilling rigs.

a cable is also excessive in a hole of even moderate diameter, so that the tools do not drop promptly on the downstroke of the walking beam, as they should for best results.

Manila drilling cables are made of a selected grade of manila hemp in long fibers, twisted especially hard to withstand the severe strain to which they are subjected. The fibers composing the strands are given a left lay or twist, while the strands making up the ropes are given a right lay. The three ropes composing the cable are tightly twisted in the reverse direction to the twist of the cable itself in order to prevent the cable from kinking readily and so that the cable will not unwind when subjected to heavy loads. This construction (see Fig. 51) results in the individual strands running parallel with the axis of the rope and there is less abrasion of the outer strands than would be the case if they assumed an angular position. To achieve an equal distribution of the load on the three ropes composing the cable, the lay of the strands, ropes and cable must be perfectly uniform throughout.

The strength of a hemp cable depends directly upon the strength of the individual fibers and the means adopted for preventing them from pulling apart. They may fail either through breakage of the fibers or by the pulling apart of the several fibers that make up the strand. Since the original fibers will seldom be more than 3 ft. long, and often a good deal less than this, it is evident that the strand depends for its strength upon the friction developed between the individual fibers by twisting. If

a strain is put upon the rope in excess of the frictional resistance to movement of the fibers, they pull apart or slide on each other. Wetting the hemp fibers will decrease their coefficient of friction. It is found that a hemp cable, properly designed to develop the amount of friction necessary to prevent it from pulling apart when dry, may lose as much as 30 per cent of its strength when wet. This of course has no bearing on the failure of the rope by direct breakage of the fibers.

The weight and strength of hemp cables of this type will vary somewhat with the quality and condition of the fiber and the care taken in their construction. Table XVII presents what are considered by a large rope manufacturing company to be average figures for the commonly used sizes of drilling cables. Hemp drilling cables usually stretch about 50 per cent of their original length during continued use so that a 1,500-ft. cable will often serve for the drilling of a 2,000-ft. hole. Hemp and manila rope deteriorate rapidly in dry climates, becoming dry and brittle and losing much of their strength and pliability. When not in use, hemp cable should be stored in a cool and moist place. Storehouses carrying a considerable stock of hemp or manila cordage should be equipped with a humidor for its preservation during the period of storage.

TABLE XVII.—WEIGHTS, SIZES AND STRENGTHS OF MANILA DRILLING CABLES*

Diameter, in.	Circumference, in.	Pounds per foot	Ultimate strength of new rope, lb.
1½	4½	.949	17,000
1¾	5¼	1.280	25,000
2	6	1.580	30,000
2¼	7	1.790	37,000
2½	7½	2.330	43,000

* Data furnished by Tubbs Cordage Company of San Francisco, Calif.

Steel Drilling Cables.—The elasticity of the hemp cable is to a large extent lacking in the steel cable until the length reaches 1,000 ft. or more, and in some regions it is customary to use the steel cable only after this depth has been attained with a hemp cable. Although something is undoubtedly sacrificed in the use of the steel cable through its lower elasticity, there are certain compensating advantages which often make its use preferable. For example, in drilling with a high fluid level in the well, the smaller diameter of the steel cable results in less displacement of water, and because of its relatively smooth outer surface it moves through the fluid with less friction. Furthermore, it is stronger, has a longer life and for deep wells is cheaper.

In order to secure the maximum of pliability, the steel cable is made of a large number of wires, usually 114, assembled in 6 strands of 19 wires each, and twisted around a hemp core which provides a cushion for the wire strands and prevents them from abrading each other (see Fig. 90). For light service, a rope made of six strands of seven wires each is sometimes used. The steel of which the wires are composed is preferably a high-grade crucible steel or plow steel, commonly used in hoisting cables subjected to severe abrasion. Table XXI gives the sizes, weights and ultimate strengths of steel cables of this type. For light work and in holes of small diameter, ¾-in. steel cables are commonly used, but, for heavy service, cables ranging in diameter from ⅞ to 1½ in. are customary.

In determining the allowable working strain on a steel cable used in oil-well service, it is customary to adopt a safety factor of five; that is, the cable used should have a breaking strength approximately five times the estimated working load. This latter quantity, however, cannot be determined precisely, inasmuch as it is influenced by many conditions the effect of which can only be estimated. Probably every cable employed in oil-well service is at times subjected to tensile stresses approaching its breaking strength, and, since the elastic limit of steel is only about 60 per cent of the breaking strength, the character of the steel will be materially altered and the useful life of the cable shortened by overstrain.

Care should be taken in selecting the size of sheaves over which the steel cable is passed or the size of drums or shafts on which it is wound to have the diameter of the sheave not less than about 30 or 40 times the diameter of the cable and preferably larger. In handling the cable, care should also be taken to avoid sharp bends or kinks which may permanently alter the alignment of the strands and wires, weakening the cable and subjecting it to abnormal abrasion.

It is often necessary to splice wire cable in adding a new length or in replacing a worn section. The "blind splice" is generally used. The strands of each of the two ends are unwound for about 15 ft., the hemp core extracted and the strands of the two ends woven together, one of the strands taking the place of the core. For drilling cables used in very deep wells, it is sometimes desirable to use a larger size of cable on the upper end than on the lower, thus making allowance for the considerable dead load of the cable as greater depths are attained. For example, in the drilling of a 7,500-ft. well in West Virginia the drilling cable used consisted of sections of $1\frac{1}{2}$-, $1\frac{1}{8}$-, 1- and $\frac{7}{8}$-in. cables with specially built tapered joints about 150 ft. in length.

The life of steel drilling cable is extremely variable and depends to a large extent on the hardness of the formations penetrated and the care with which it is handled. In some cases a cable may be worn out in the drilling of a single well. In drilling the 7,500-ft. well mentioned in the previous paragraph, ten 8,000-ft. drilling cables and three $\frac{9}{16}$-in. sand lines were used. In order to secure in some measure the advantage of the more elastic hemp cable, some drillers fasten about 100 ft. of hemp cable on the lower end of the steel cable. This "cracker line," or "snapper line," so called, has in addition the advantage of the small diameter and low cost of the steel cable. It is chiefly used in the oil fields of Illinois, its use in Western drilling practice being uncommon.

The Casing Line (or "Calf Line").—Although the calf line is not subjected to the destructive jar and rapid variation in intensity of strain that are characteristic of drilling operations, the load to be sustained by it is occasionally greater than that imposed on any other cable in the rig. The dead weight of a long column of heavy casing suspended on this cable is alone sufficient to place it under considerable tension, and since this may be exceeded by the frictional resistance of the "formation" in lifting the casing, it is apparent that at times the material will be stressed to a degree that will exceed its elastic limit.

The casing line, it will be recalled from the foregoing general description of the rig, is coiled on the shaft of the calf wheel, the free end being carried over the crown block and threaded back and forth between two or more casing pulleys and the sheaves of the hoisting block. The

end of the cable, or dead line, is attached either to the bail of the hoisting block or to the derrick sills. The number of lines strung between the derrick crown and the hoisting block determines the tension in the line that is developed during the lifting of a given load. The actual strain may be computed by dividing the weight of the load to be lifted by the number of lines.

The casing line is usually constructed of steel wire, being designed particularly to withstand severe tensional strain. It must be pliable in order that it may bend to the rather small diameter of the sheaves over which it passes without abnormal bending stresses. The construction is quite similar to that of the steel drilling cables described above, the cable built of six strands of 19 wires each, with a hemp core, being a common type. Diameters ranging from ¾ to 1 in. are customary (see Table XXI). The material may be softer, however, since the outer strands are not particularly subjected to abrasion, which is an important factor to consider in the selection of a drilling cable. For the drilling of very shallow wells, or in regions where only light casings are used, the casing line may be of hemp instead of steel. In such cases the calf wheel may be omitted in the equipment of the rig and the casing line coiled on a part of the bull-wheel shaft, or the drilling cable may be detached from the tools and used for handling casing.

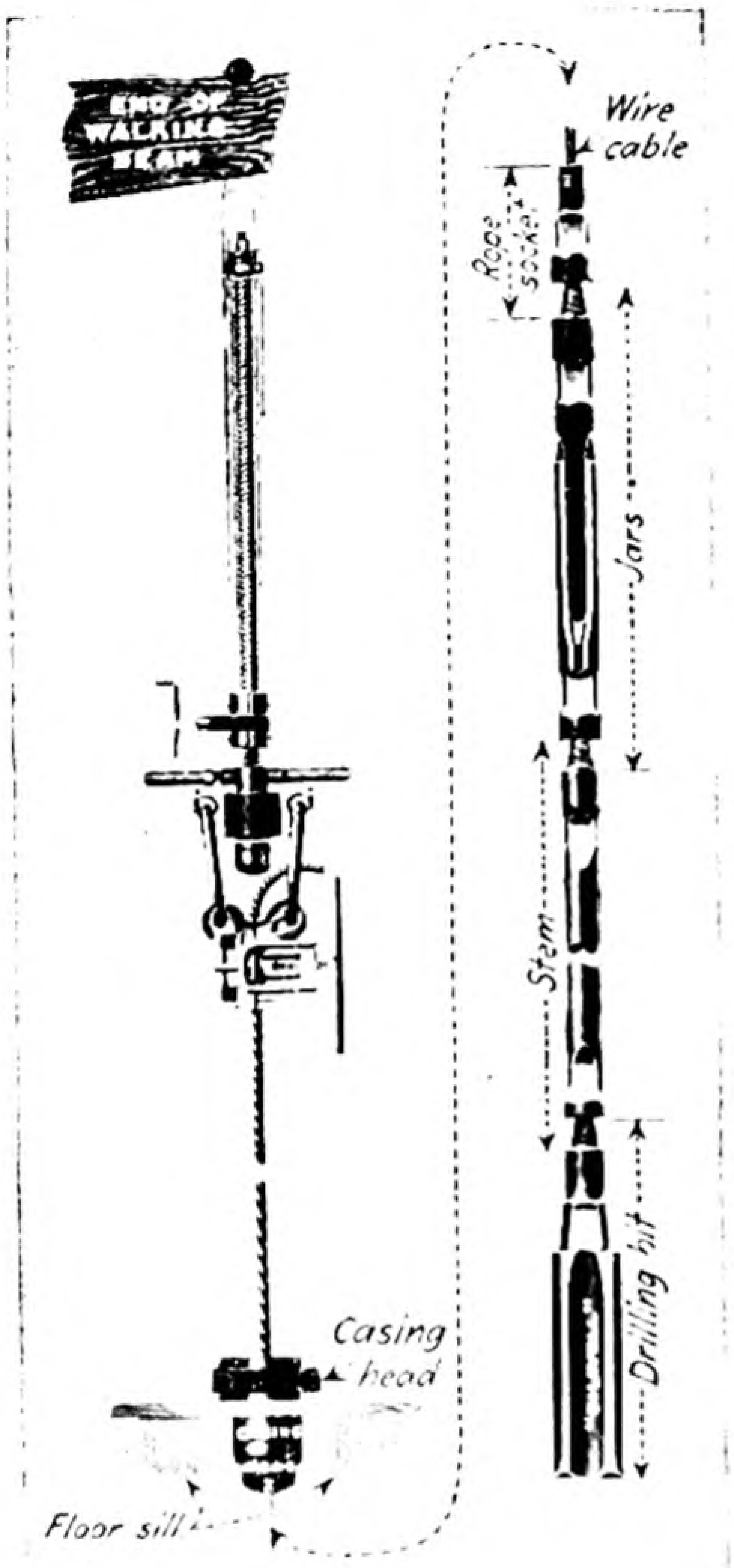
The Sand Line.—The strain which the sand line will be required to sustain is comparatively small, since the dead load of the bailer and its contents seldom exceeds 2 tons even in the larger sizes of bailers. It is, however, subjected to considerable abrasion, as a result of contact with the walls of the well and casing during operation of the bailer. In addition, it must be sufficiently pliable to bend freely over the sand pulley at the crown block and to wind without abnormal strain on the drum of the sand reel.

For service of this character a flexible steel wire cable composed of six strands of seven wires each, wound on a hemp core, has been found satisfactory. Diameters range from ⅜ to ⅝ in., the ½-, $\frac{9}{16}$-, and ⅝-in. sizes being commonly used. The smaller sizes are appropriate only in shallow wells. Manila sand lines ranging in diameter from ⅝ to 1¼ in. are occasionally used in shallow wells, but their life is short because of the continual surface abrasion and alternate wetting and drying to which they are subjected.

Guy Wires.—For guying derricks it is customary to use a galvanized wire strand composed of seven wires twisted into a single strand. Available diameters range from $\frac{5}{64}$ to ⅝ in.

Bull Ropes.—The rope drive connecting the tug pulley on the band wheel with the rim of the left-hand bull wheel consists of one or two endless hemp or manila ropes, 2 or 3 in. in diameter, built of a large number

of small strands loosely twisted together, forming a strong and exceptionally pliable rope (see Fig. 51). The bull ropes are frequently thrown from their grooves during the manipulation of the tools by the side thrust of a wooden lever mounted near the bull wheels. The ropes are crossed between the tug pulley and the bull wheels in order to reverse the direction of the power, and, except for the rubbing of the ropes on each other where they cross, and occasional slippage in the grooves in which they run, there is little abrasion. The life of the bull rope is influenced chiefly by the strain put upon it, resulting in direct breakage of the strands and pulling apart of the fibers.



(*Courtesy of Oil Well Supply Co.*)

FIG. 52.—The "string" of cable drilling tools showing, at left, the drilling cable suspended from the end of the walking beam by the temper screw; at right, the assembled string of tools that enters the well.

Other cordage used in the derrick is of minor importance, consisting for the most part of hemp rope or light steel wire strands used in supporting the heavy casing tongs, connecting the temper screw with its counterbalance, connecting the "telegraph wheel" with the engine throttle and like purposes.

String of Cable Drilling Tools

The string of cable drilling tools consists of several parts (see Fig. 52), securely fastened together by tapered screw ("pin") joints. The rope socket which connects the tools with the drilling cable is screwed to the top of a pair of massive telescoping metal links called "jars." These in turn connect at their lower end with a long cylindrical steel "drill stem," and the latter is screwed to the top of the drilling bit. Occasionally a "sinker bar," a short cylindrical steel bar, is inserted between the top link of the jars and the rope socket. The total length of the string of cable tools so connected is usually about 40 ft. The aggregate weight depends upon the size of hole to be drilled; for a 10-in. hole it averages about 3,600 lb.

Cable drilling bits are of several types differing slightly from each other in form and purpose (see Fig. 53). The bit is made of a heavy bar of steel or iron, from 1 to 11 ft. long (commonly 7 or 8 ft.) and somewhat wider than it is thick. It is dressed to a blunt edge on one end and

terminates in a tapered "tool joint" at the other. The upper shank of the bit, which is somewhat smaller than the cutting edge, is flattened just below the joint to facilitate the application of a wrench in screwing it to the drill stem. A wide groove or "water course" is cut down each side of the tool to permit of the easy displacement of the fluid in the well as the tools rise and fall.

The form of the cutting edge is varied to adapt it to the character of the rock formation to be drilled. For hard rocks, a fairly sharp chisel edge is used; for soft material the bit will be almost flat on the bottom with only a blunt edge at the center. A chisel-edged bit operating in soft rocks will loosen the material faster than it can be mixed with water, so that the bit rapidly becomes clogged. In "dressing" the bits, particular attention is given to shape the edges and corners properly, since the size of the hole drilled and the clearance of the bit in the hole depend largely upon these details. For soft rocks the cutting edge will be dished in somewhat toward the center so that the corners project slightly. In hard rocks the cutting edge should be almost a straight line, in order to distribute the wear on the bit uniformly and to prevent breakage of the corners.

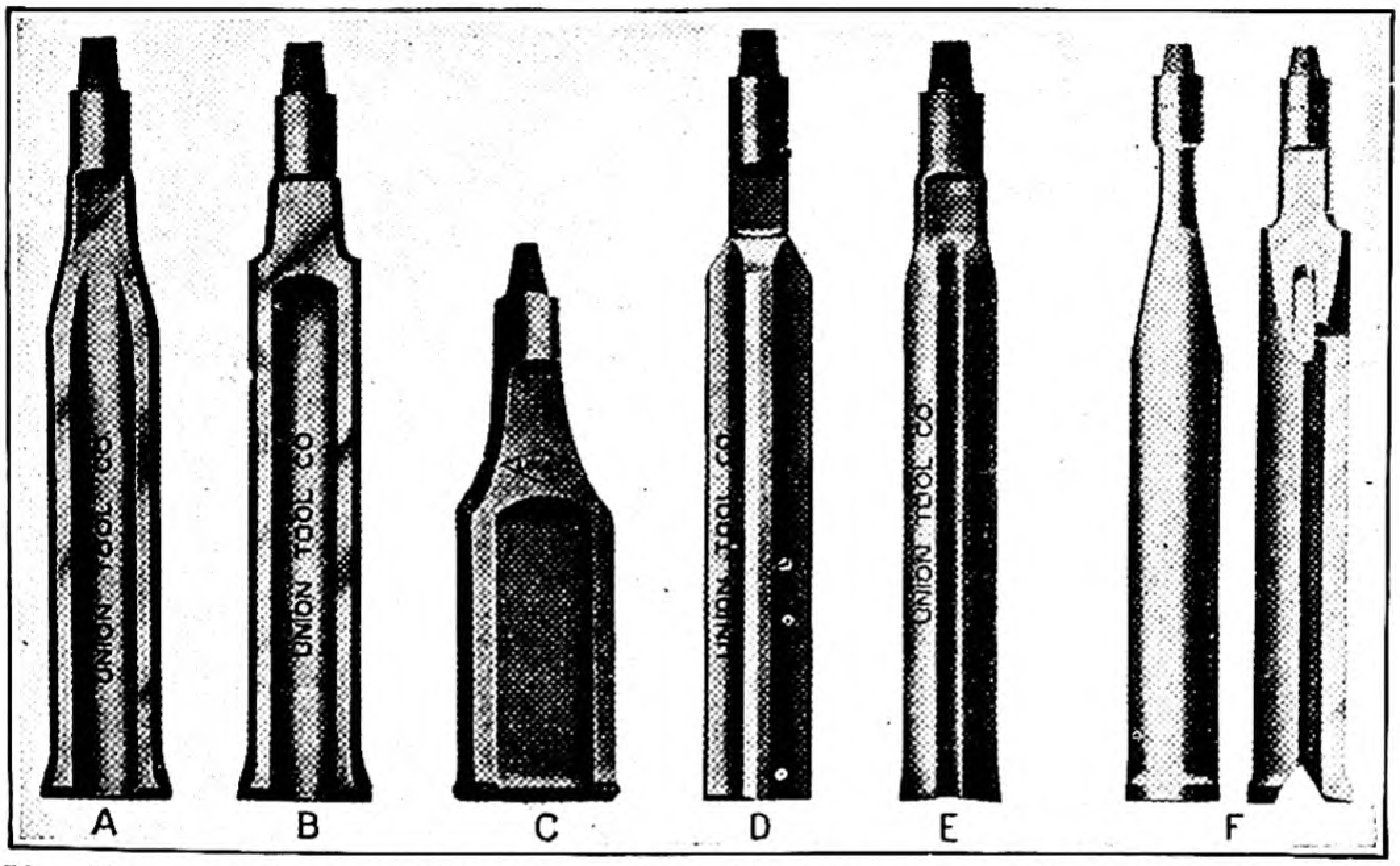


FIG. 53.—Types of churn drilling bits. *A*, California pattern; *B*, Mother Hubbard pattern; *C*, spudding bit; *D*, star bit; *E*, round reamer; *F*, Overman bit.

Several common types of cable-tool bits are illustrated in Fig. 53. The California pattern represents a widely used type, though the Mother Hubbard pattern is preferred by many drillers, particularly in north Texas, on account of its angular form, which, it is claimed, results in the drilling of a straighter hole. The spudding bit is a short, broad form used only in starting the well. The star bit and reaming bits

are used for straightening a crooked hole and enlarging the diameter from the top down. In another style, the spiral bit, the blade is twisted about the vertical axis of the tool so that the edges and water courses assume a spiral appearance. The shank of the bit is usually made several inches smaller in diameter than the cutting edge, which permits the bit to work in the hole eccentrically, thus drilling a hole somewhat larger than the actual gauge of the bit.

Drilling bits are preferably made of a good grade of tool steel which may be accurately tempered to the proper degree of hardness and which holds its cutting edge and resists abrasion. Chrome and other special steels are occasionally used. To reduce the cost, some manufacturers use tool steel only on the lower one-third of the bit, the shank and upper end being composed of a cheaper grade of forged iron or mild steel. This practice is permissible if the weld connecting the two metals can be satisfactorily made. The bits are seldom dressed back in resharpening to more than one-third of their original length before they are discarded or a new piece of steel is welded on. The metal comprising the upper part of the bit is useful only in adding weight.

Too little attention is given to the proper tempering of drilling bits for best results. The hardness of the rocks to be penetrated should always be considered in tempering the steel. The work of sharpening and tempering the bits is often entrusted to the driller and his tool dresser, who are frequently not sufficiently skilled in the art of tempering and heat-treatment of steel for best results. Furthermore, the equipment provided at the rig for this work is often inadequate. A better practice would seem to be to send the tools to a well-equipped forge shop where they may receive the attention of a skilled tool sharpener.

Difficulty is experienced, especially with the larger sizes of bits, in cracking or breaking of the metal, particularly at the corners and through the thinner metal separating the water courses. This is usually a result either of uneven heating or of using too hard a temper. Large bits should be heated in a very slow fire and frequently turned, special care being taken to avoid overheating the corners, edges and thinner portions. The metal should be tempered to a straw color on the cutting edge, plunged and allowed to cool slowly with the cutting edge immersed in 1 in. of water or mud. Bits dressed with an uneven cutting edge frequently break at the pins or in some cases at the wrench squares.

The tool joints, used in connecting the several parts of the string of cable drilling tools, are equipped with taper-screw threads in order to facilitate coupling and uncoupling of the parts (see Fig. 54). They are made of soft annealed steel and are provided with shoulders about 1 in. wide between the threads and the outer circumference of the box. When the shoulders on the two parts of the joint butt together, the friction

developed prevents unscrewing as a result of vibration in the well. When the joints are in good condition, they can be screwed by hand until they come within about $\frac{1}{16}$ in. of shouldering, after which a wrench operated by a powerful circle jack bolted to the derrick floor must be applied (see Figs. 55 and 56). When the joints are new, they should be set up by the jack and unscrewed several times before being put into use. They should always be thoroughly clean, free from grease and rust, and

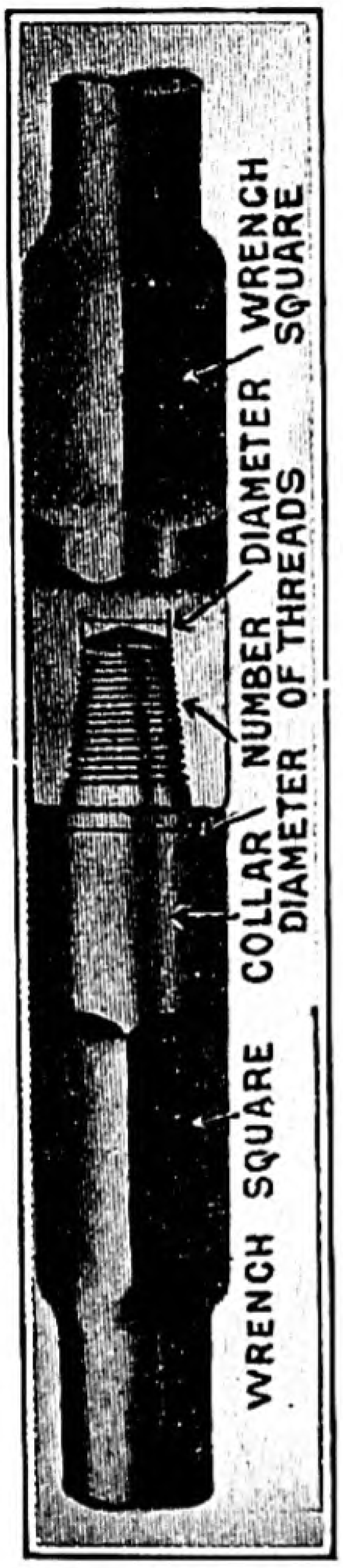


FIG. 54.—Detail of tool joint.

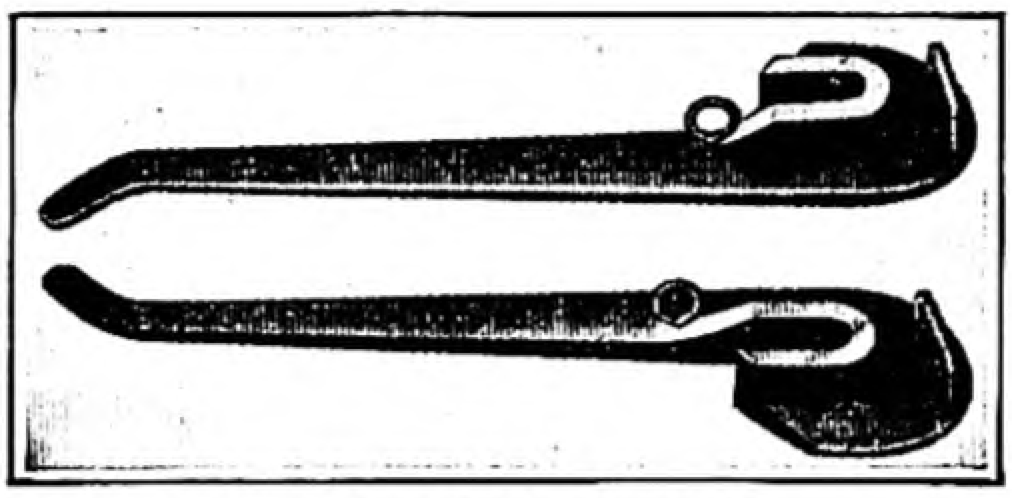


FIG. 55.—Tool wrenches.

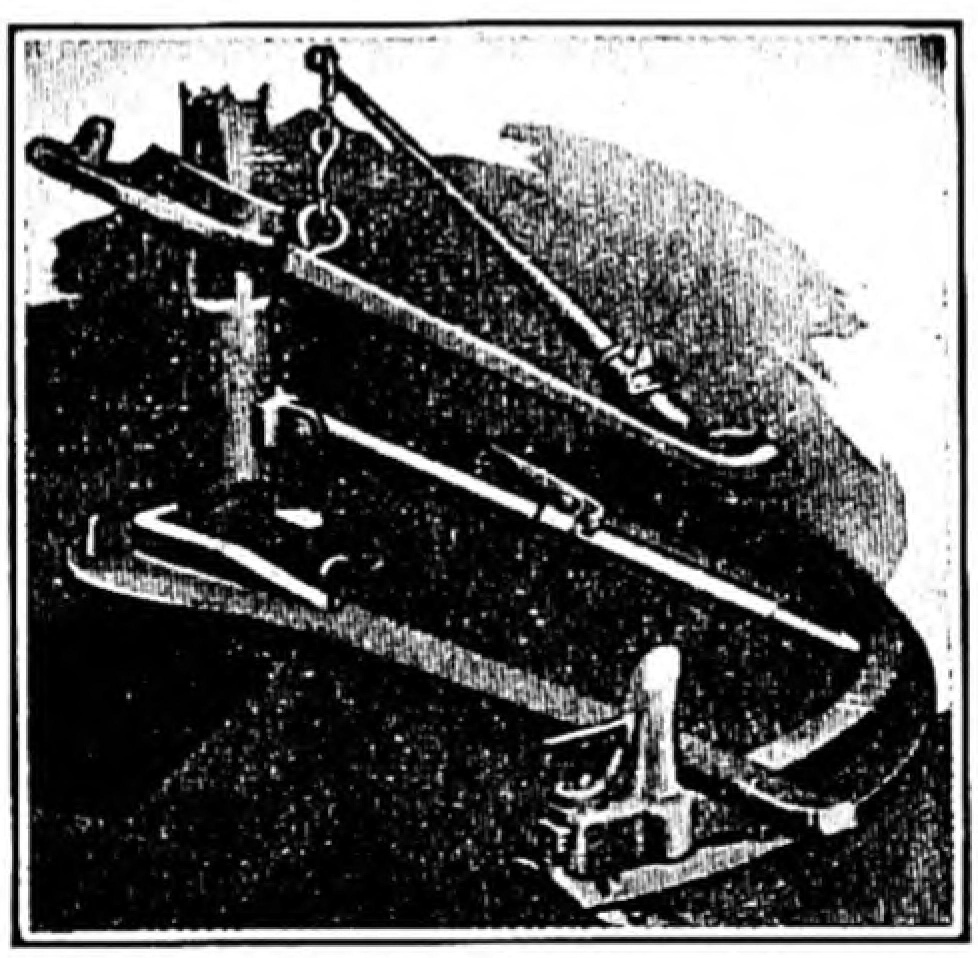


FIG. 56.—Circle jack in position for setting up tool joint.

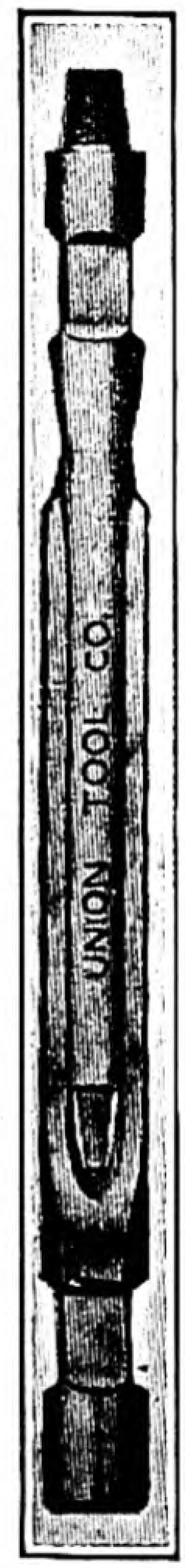


FIG. 57.—Drilling jars.

the shoulders should be smooth so that they butt properly together. When the threads become cupped as a result of excessive strain put upon them, they should be sent to the shop for rethreading.

For the larger sizes of tools the joints are usually 4 in. in diameter at the base and taper to 3 in. at the top. They are cut with seven threads to the inch, and are known as "3- by 4-in.-7 joints." The threads may be sharp 60-deg. V threads or they may be flattened as in the U.S. standard thread. The outer diameter of the metal "box" is usually 6 in. Other commonly used sizes of tool joints are 4 by 5 in.-7, $2\frac{3}{4}$ by $3\frac{3}{4}$ in.-7,

2 by 3 in.-7 and 1¾ by 2¾ in.-8. The size of the pins must be proportioned to the size and weight of the tools; otherwise the string of tools is apt to pull apart at a tool joint ("jump a pin") during operation in the well. For heavy work in north central Texas it is customary to use a 5½-in. by 30-ft. auger stem equipped with a 4- by 5-in. box and a 3¼- by 4¼-in. pin. The drilling jars used are 6½ in. and are equipped with a 3¼- by 4¼-in. box and pin. The A.P.I. has standardized tool joints, so that the equipment of different manufacturers may be used in making up a string of tools.

The drill stem, or auger stem as it is occasionaly called, is a cylindrical bar of mild steel or iron equipped with a tool joint and wrench squares at either end. The function of the stem is merely to add weight to the drilling bit. The size varies with the diameter of the hole to be drilled, ranging from 2½ to 6 in. in diameter and from 6 to 42 ft. in length. A spiral form of drill stem, supposed to give the tools a rotating motion as they rise and fall through the well fluid, is preferred by some drillers.

The drilling jars resemble two great links of a chain and are carefully made to slide on each other or telescope (see Fig. 57). The two links are of massive construction, reinforced at the ends where they engage each other and provided with tool joints at the outer ends. They are of such length that they may telescope for a distance of about 16 in., though "fishing jars" of similar design may have a stroke of as much as 36 in.

The purpose of the jars is to enable the driller to strike a sharp upward blow on the drilling bit, which is frequently necessary in freeing it from clay or shale in which it tends to stick. By adjusting the stroke and the position of the tools in the well, the jars may be allowed to telescope for from 6 to 12 in. on each downstroke. On the upstroke the upper link gathers momentum before it engages the lower, and the tools are suddenly jerked from the sticky material which tends to hold them. In other cases the bit may become wedged in the hole, or caving of the walls may necessitate the application of a succession of upward blows before the tools can be freed. The jars are often able to loosen the tools when a direct pull on the drilling cable would be quite ineffective. The jars are not brought into play or can be omitted from the string of tools when drilling in hard rocks.

The sinker bar is similar to the drill stem in form, except that it is shorter. It is used merely to add mass to the weight of the upper link of the jars, thus making the latter more effective in freeing the tools on the upstroke.

The rope socket, which serves to connect the string of tools with the drilling cable, may be one of several types. Those intended for use with hemp cable necessarily differ in form from those used on steel wire cable. The form of the socket should be such that the cable is not subjected to

any sharp bends on which it is likely to break, and it should provide a positive grip, strong enough to resist any pull short of that necessary to break the cable. In addition it must be substantial to withstand the wear

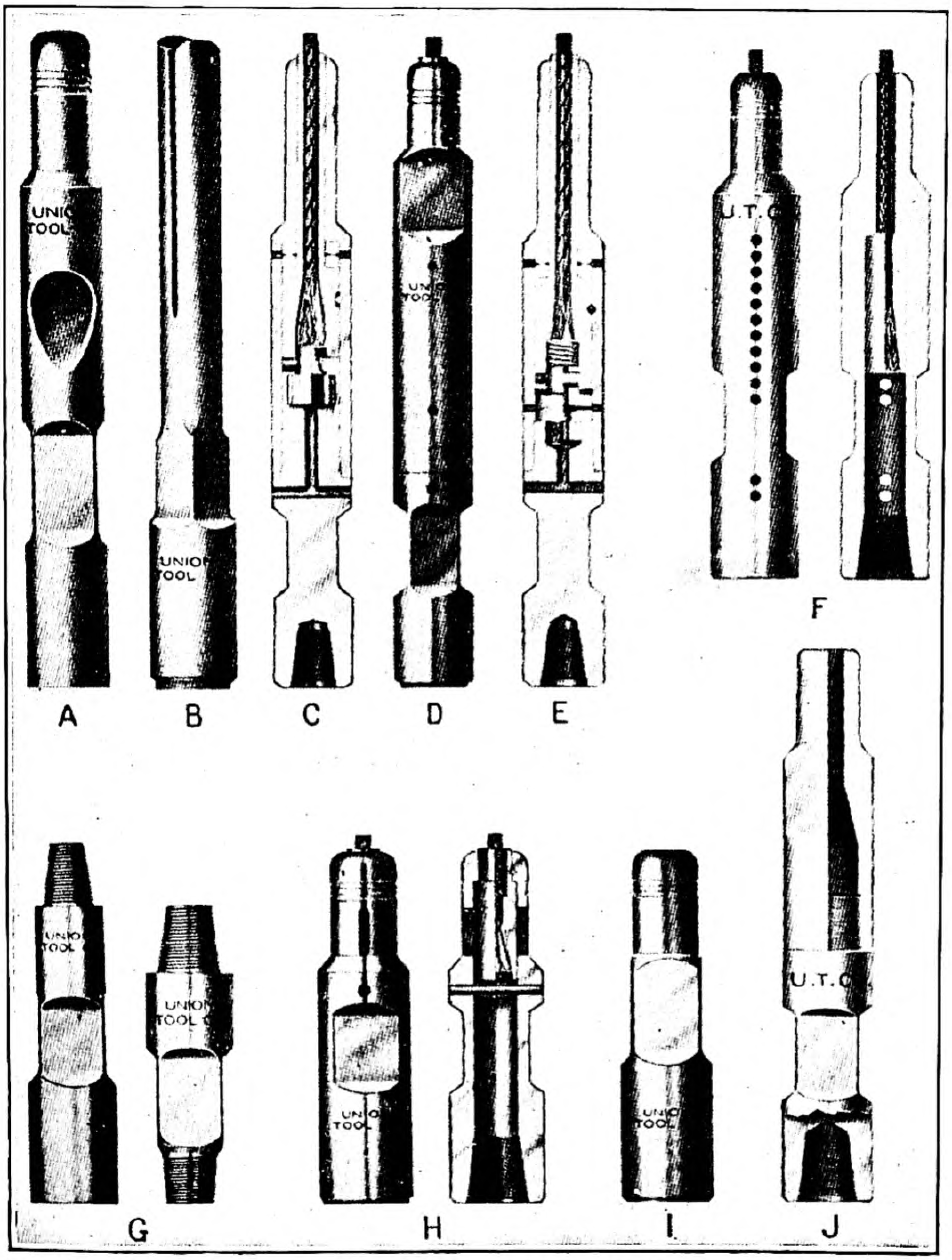


FIG. 58.—Types of rope sockets. *A*, New Era socket; *B*, wing socket; *D*, Union rope socket; *C*, ratchet type; *E*, roller-ratchet type; *F*, Prosser socket; *G*, types of substitutes; *H*, double-swivel socket; *I*, Babcock socket; *J*, Babcock manila-rope socket.

and abrasion to which it is subjected, and it should provide a means of conveniently connecting with the drilling tools.

For hemp drilling cables, the New Era socket and the wing socket with rivet fastenings have been widely used (see Fig. 58). In the case of wire

rope the strands are usually unwound or loosened slightly at the ends and babbitted in a conical recess provided in the socket. The Babcock socket is the best known example of this type. In the Prosser socket the cable is held by a pair of cone-shaped slips with serrate teeth, which grip it securely when they are drawn up into position. Some drillers consider it an advantage to be able to rotate the drilling tools, with the thought that this procedure prevents them from striking repeatedly in the same place, thus avoiding a "flat" hole. Although the necessity for this rotation of the tools is doubtful since they naturally turn in the hole as the tension in the long cable is alternately applied and released, some manufacturers have catered to this whim of the driller in the design of ratchet rope sockets which permit of the lower half of the socket turning with respect to the upper half. The Union roller-ratchet socket is an example of this type.

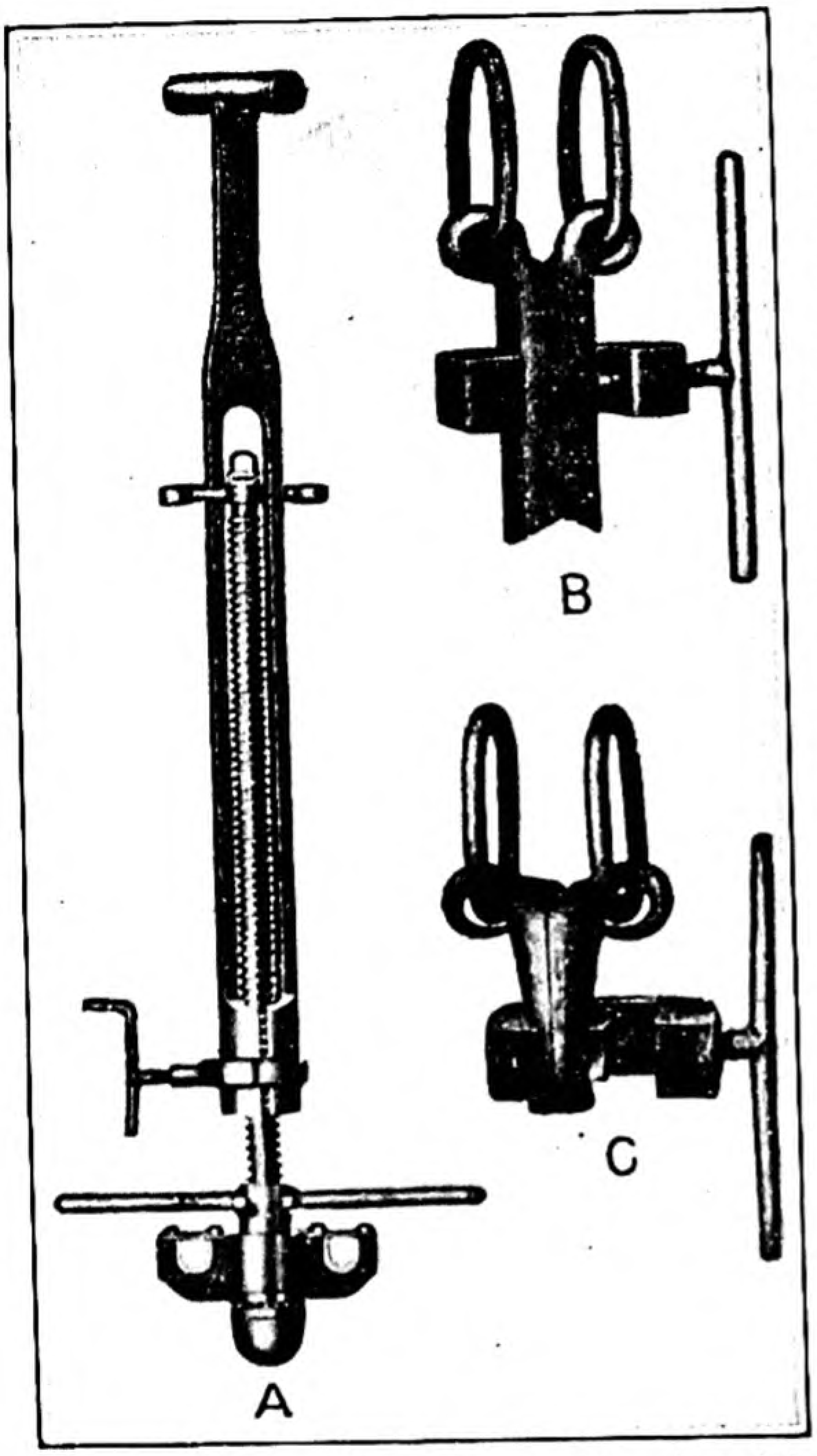


FIG. 59.—Temper screw *A* with drilling cable clamps for steel wire cable *B* and for manila cable *C*.

A variety of forms of substitutes for connecting the rope socket with tubing or with the many types of fishing tools are available, as well as rope clamps, clips and thimbles used in forming and supporting loops made in the end of a cable.

The temper screw is the device by means of which the drilling cable and tools are suspended from the walking beam, and with the aid of which the tools are gradually lowered so that they continue to strike the bottom of the hole as it is deepened. Figure 59 shows that it consists of several parts. A substantial metal frame, suspended by a T bar at its upper end from a slot in the "nose" of the walking beam overhanging the well, supports a split nut between the two reins at the bottom. The two halves of this nut spring slightly apart with the reins in their normal position, but by means of a small elliptical clamp they can be brought together so that their threads engage those of the screw. The screw is from 5 to 8 ft. in length, 2 in. in diameter and cut with a coarse square thread. Attached to the lower end of the screw is a handle by means of

which it can be turned, and a pair of links supporting a clamp which grips the drilling cable. The links pass through holes in a short metal crossbar or swivel, resting on a shoulder cut on the end of the screw. Frequently, cone or ball bearings will be placed between the crossbar and the supporting shoulder so that the screw may be revolved freely without turning the links or rope clamps.

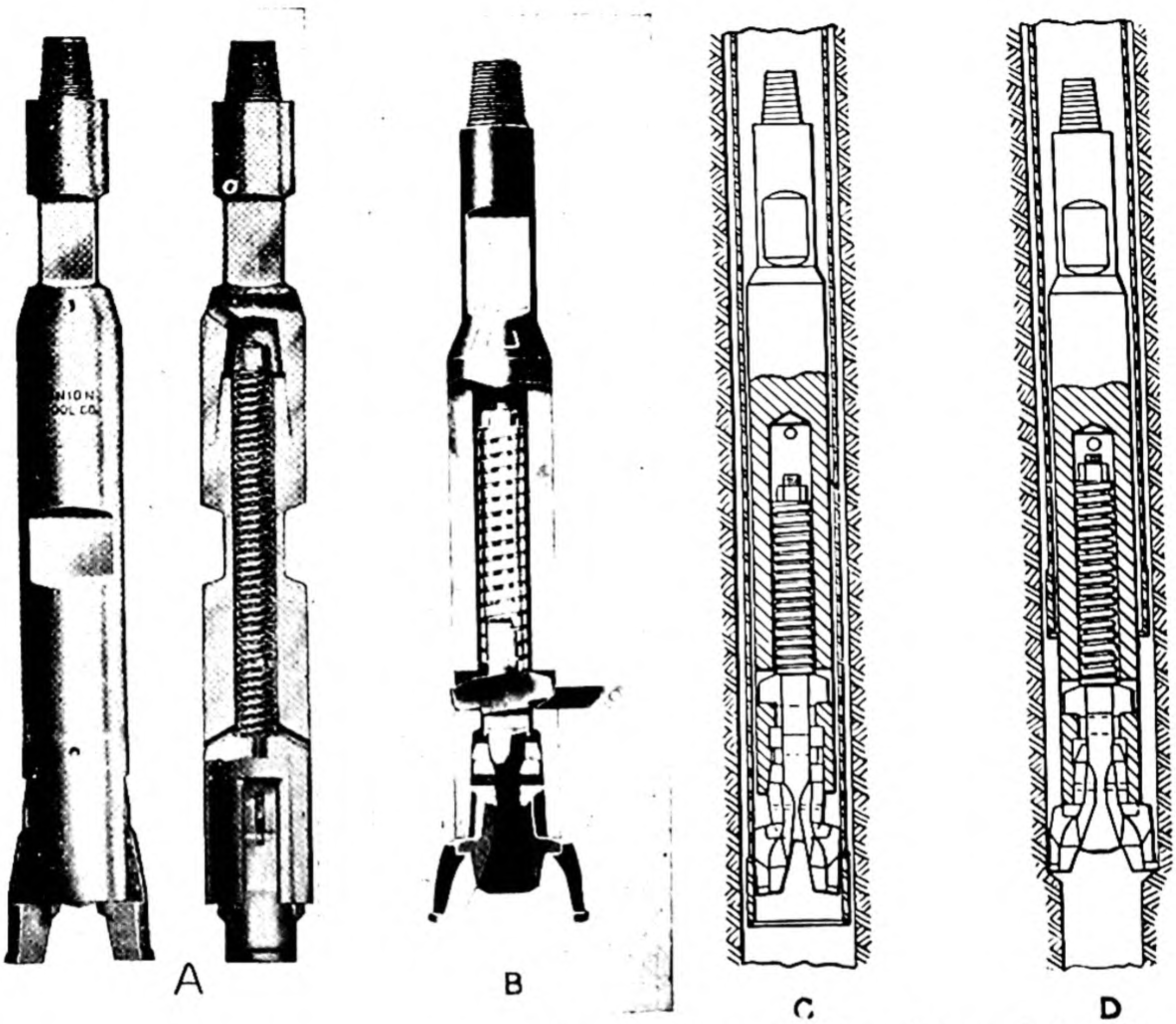
The form of the rope clamps will vary with the kind of drilling cable used. They must be of such shape that they will not damage the drilling cable, and yet they must apply sufficient pressure to prevent it from slipping through. When a manila drilling cable is used, it is customary to wrap loose strands of old rope about it at the point where it is gripped by the metal clamps. This additional material is so adjusted that it forms a wedge in the upper part of the conical opening in the clamp. For steel drilling cables the clamps consist of two bars of steel with grooves cut through the center to fit the size of the cable being used.

By turning the handle in the lower end of the screw, the latter can be advanced into the split nut until the full length of the screw has passed through. In order to take a new grip on the cable so that drilling can be continued, the weight of the drilling cable and tools must be transferred from the beam to the crown block and the temper screw loosened on the cable. By loosening the clamp which holds the two halves of the split nut together, the reins spring apart, releasing the nut from the screw which can then be lifted to the top of the frame. The two halves of the nut are then again clamped about the screw, the lower clamps are attached to the drilling cable, the weight of the tools is transferred back to the beam and drilling is resumed.

The weight of the temper screw and all its parts will vary from 300 to 500 lb., depending upon the length of the screw and the depth of well for which it is intended to serve. To aid in lifting the screw in the frame, it is usual to attach to its upper end a rope which passes up over the top of the beam and thence down to a balance weight at the side of the samson post.

The circle jack, by means of which the several parts forming the string of cable tools are screwed together, consists of a semicircular toothed rack which is fastened to the derrick floor around the mouth of the well (see Fig. 56). At one end of the toothed rack a large wrench is held in a stationary position. A second wrench is attached to a traveler containing a ratchet operating on the toothed rack. As the handle is moved backward and forward, the ratchet moves forward one tooth on the rack for each stroke of the handle, thus advancing the movable wrench. In applying the circle jack the tool forming the lower portion of the tool joint is lowered into the well until the wrench square is just level with the derrick floor and is gripped by the stationary wrench.

The wrench square on the upper portion of the joint is then gripped by the movable wrench and the traveler is advanced on the rack until the joint is tight. The joints are generally screwed together as far as is possible by hand, before being lowered into the well and tightened by the circle jack.



(*Courtesy of Union Tool Co. and Byron-Jackson Co.*)

FIG. 60.—Wilson-type cable-tool under-reamer. *A*, side and edge views; *B*, method of releasing lugs; *C*, under-reamer descending through casing with lugs collapsed; *D*, under-reamer at work, with lugs expanded, below casing shoe.

Under-reamers.—It frequently happens, especially in drilling through hard rocks, that the drilling tools do not maintain sufficient clearance to permit of free passage of the casing. In such a case an under-reamer may be lowered to the tight place and manipulated in such a way as to enlarge that particular section to the necessary diameter. Under-reamers also find application in reaming out holes at points where free space about the casing is desired for the introduction of cement in excluding water.

A number of different forms of under-reamers have been designed and

are available from the tool supply companies. Of the various types on the market the Wilson pattern is perhaps best known (see Fig. 60).

The under-reamer is equipped with two lugs having specially formed and hardened cutting edges, mounted in the body of the tool in such a way that they expand outward under the influence of a powerful spring. The lugs are held in the collapsed position by a wire or light metal ring while the tool is being lowered through the well casing, but on emerging from the casing shoe they are forced outward into working position by the spring. With lugs fully expanded some under-reamers are capable of drilling a hole 3 in. larger in diameter than that of the casing through which they pass.

The under-reamer is churned up and down in the same manner as the ordinary drilling bit, gradually enlarging the hole to the limit of expansion of the lugs. On withdrawing the under-reamer from the well, the lugs are compressed into the body of the tool against the pressure of the spring as they enter the casing shoe. The moderate side pressure of the lugs against the inner walls of the casing introduces slight resistance to withdrawal of the tool.

In operation, the brunt of the contact with the rock walls of the well falls directly upon the cutting edges of the lugs, which are consequently rapidly dulled. Care should be taken in dressing the lugs to give them a hard temper in order that they may better resist abrasion. If the steel is too hard, however, the edges become brittle so that they break in service. Some operators find that a little hard fusion metal melted on the cutting edges of the lugs with an oxyacetylene torch greatly increases their useful life. Under-reamer lugs are frequently made of chrome or manganese steel, which are tougher and more resistant to abrasion than ordinary tool steel. The lugs are forged on special anvils or dressing blocks, recessed to conform with their peculiar shape.

Bailers, used in removing from the well the pulverized rock loosened by the bit during the process of drilling, are constructed of a pipe of suitable size in the lower end of which are fastened a reinforcing shoe and valve. At the upper end a bail is provided for attaching the sand line. Short bailers may be used when the well is shallow and large in diameter, but for great depths, and where the diameter of the well is small, the length must be increased to as much as 20 or 30 ft., occasionally even 40 ft., in order to handle a greater quantity of material with each trip of the bailer to the bottom.

Bailer valves are of two types. The disk valve is hinged at one side, opening upward (see Fig. 61). The dart valve is spherical or ovoidal in form and has attached to it, on its lower side, a metal stem or dart which passes through the circular valve seat and projects beyond the lower end of the supporting shoe. In the case of either type of valve, upward

pressure of the well fluid on the descending bailer raises the valve so that the fluid passes through until it rests upon the bottom of the well. The bailer is then raised and dropped a few feet ("spudded"), the process being repeated several times in order to force as much as possible of the sand and clay through the valve. On hoisting the bailer, downward pressure at once closes the valve so that even though the top is open no fluid is displaced. On emerging from the well, the bailer is dumped—

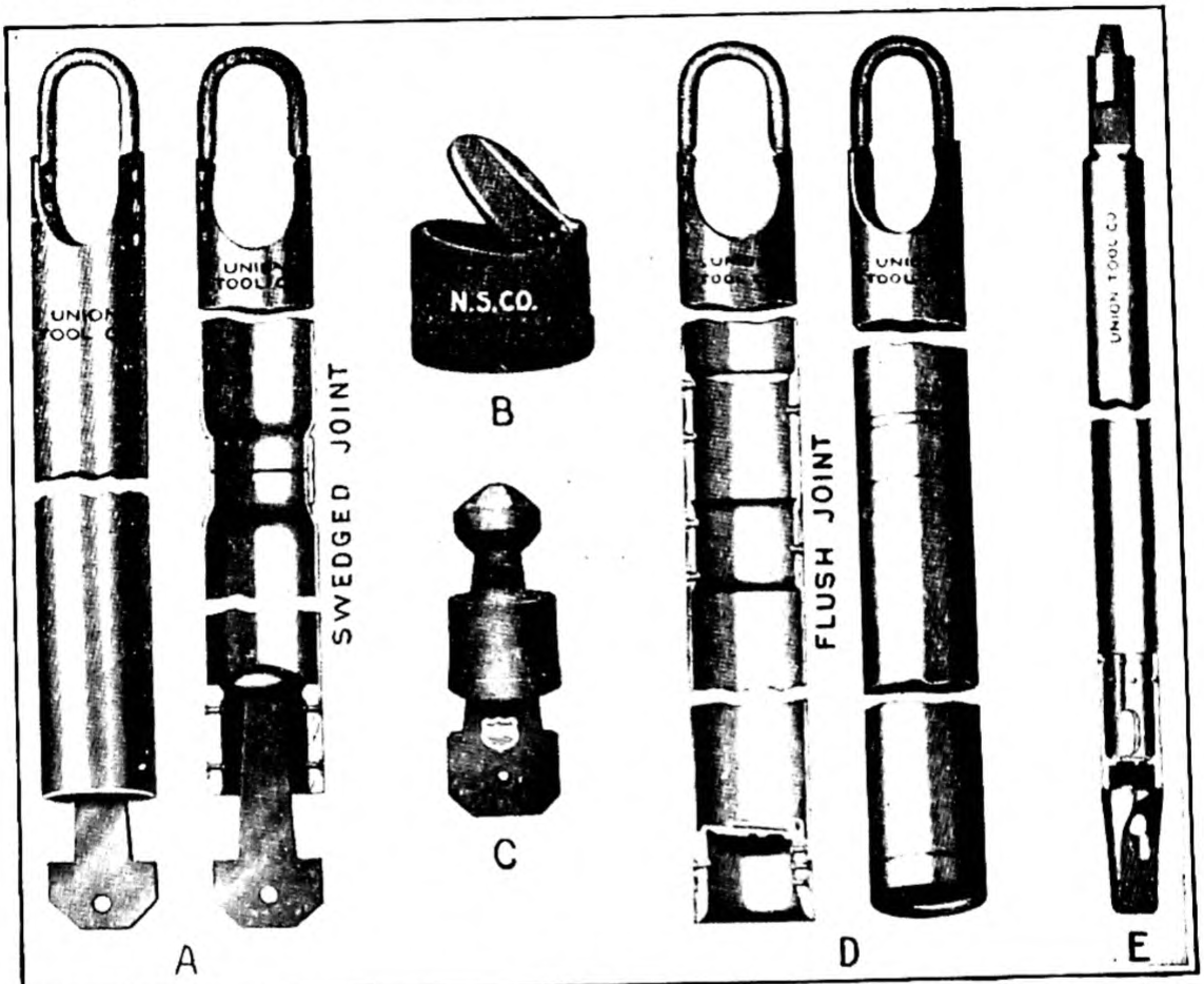


FIG. 61.—Types of bailers. *A*, dart valve bailer; *B*, disk valve; *C*, dart valve; *D*, disk valve bailer; *E*, combination bit and mud socket.

in the case of a bailer equipped with a dart valve, by lowering it into a wooden trough, the upward pressure of the trough bottom on the dart lifting the valve from its seat, thus permitting the contents of the bailer to flow out. In dumping a bailer equipped with a disk valve, it is lowered over an upright metal pin mounted in the trough, which lifts the valve on its hinge.

The main body of the bailer is often made of well casing 2 or 3 in. smaller in diameter than the casing through which it must operate. Occasionally a spirally riveted sheet-metal pipe will be used for light service. If a long bailer is needed and more than one joint of pipe must be used, two or more sections may be connected end to end with swaged or flush-riveted joints. The bail and reinforcing shoe are also riveted in

position on the ends of the pipe. The reinforcing shoe is of cast steel and is provided to prevent wear and distortion of the lower end of the bailer, which is subjected to considerable abrasion during the process of lowering and spudding it in the well.

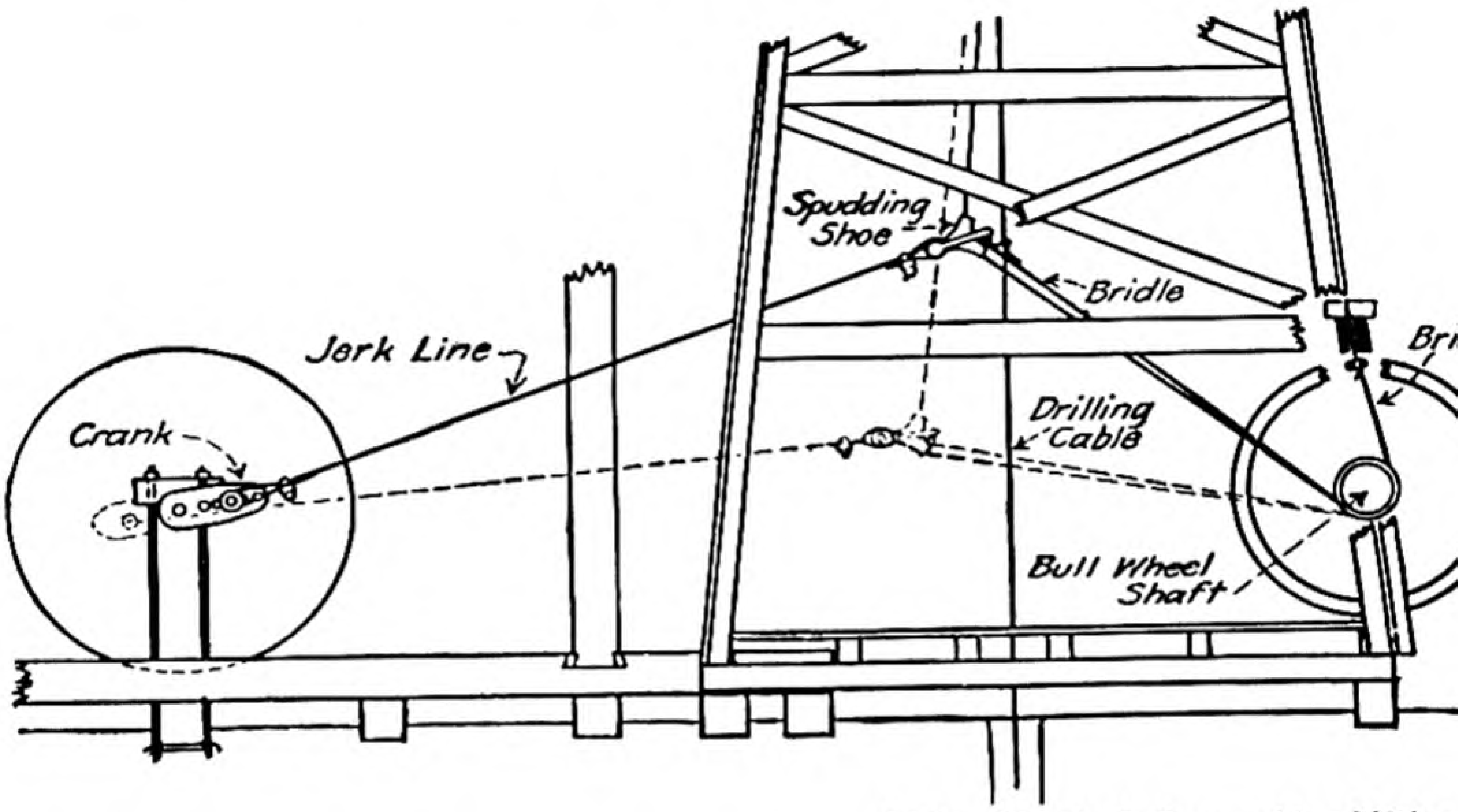
Sand Pumps.—If the fragments of rock loosened by the drill are coarse, they settle rapidly to the bottom and it will be difficult to get them into the ordinary type of bailer. For such conditions it is customary to make use of a sand pump, which is similar to an ordinary bailer in general construction and form except that it is provided with a piston or plunger which can be moved up and down in the cylindrical shell to create suction helpful in drawing coarse material past the valve. In one type of sand pump the sand line is attached to the top of a plunger rod instead of to the bail. A slot in this rod, straddling the bail, permits the piston to be raised a number of feet as the sand line is hoisted, before the plunger engages the bail and lifts the main body of the pump. The Cavins bailer utilizes a spring-actuated pneumatic device which develops a powerful suction effect.

Mud Sockets.—When soft clay or mud must be penetrated by the well, or when such materials have had time to settle into a solid mass in the bottom of the well, the bailer is not always effective in removing them. They can be easily penetrated by the drill but settle rapidly before the tools can be withdrawn and the bailer lowered. In such cases a "mud socket" (see Fig. 61) may be substituted for the drilling bit on the bottom of the string of cable tools. This device consists of a heavy metal tube equipped with a beveled reinforcing shoe and inclined disk valve within the lower end. It is churned up and down within the well until full of mud or clay, when it is withdrawn for cleaning. For work in very stiff muds or clays the socket is sometimes also provided with a sharp chisel-edged bit attached to the shoe in such a way that it does not interfere with the passage of material through the valve.

DRILLING WITH THE CABLE TOOLS

Spudding.—Since the complete string of cable tools is 40 ft. long or more, there is not sufficient headroom to conduct drilling operations with the aid of the walking beam until a depth of at least 60 ft. is attained. The first 60 ft.—frequently several hundred feet—of the well is therefore drilled by a process known as "spudding," which does not involve the use of the beam. A special spudding bit is used which is shorter than the usual pattern, and a short stem without jars. The drilling bit is lowered to the bottom of the cellar inside of the conductor, a little slack is allowed in the cable and the bull wheels are securely locked with the brake. A spudding shoe is then placed on the drilling cable a short distance above the bull-wheel shaft, and a jerk line connecting with the wrist pin on the

crank is attached to the clevis of the shoe (see Fig. 62). With each revolution of the crankshaft, the tools are lifted a short distance and dropped on bottom. By occasionally releasing the bull-wheel brake and letting out more of the drilling cable, the tools may be kept striking on bottom. Progress is often slow by this method, but deficiencies of the method are usually offset to some extent by the soft character of the surface strata. Operation of the drilling tools must, of course, be occasionally interrupted to bail out the material loosened by the drill. It is preferable to use a manila drilling cable during the spudding process,



(*After W. H. Jeffery, with additions.*)

FIG. 62.—Method of spudding.

since the action with a steel cable is somewhat detrimental to the rig, particularly if the rig is a light one.

"Hitching On."—When sufficient depth has been attained to permit of operating the full string of tools with the walking beam, the spudding equipment is removed, the temper screw is adjusted in position on the end of the beam and the complete string of tools with a regular pattern drilling bit is assembled. Care is taken, as the tools are lowered past the derrick floor, to set up each tool joint with the circle jack to make certain that all are tight. The tools are lowered by partly releasing the bull-wheel brake until bottom is reached. When lowering the tools into the well, the driller applies the bull-wheel brake at intervals of a few feet when nearing the bottom in order to stop the descent just as the tools reach bottom on the full stretch of the cable. In drilling, the tools should strike bottom while the cable is extended to the limit of its elasticity, thus ensuring the maximum rebound. This elastic rebound probably increases the effective stroke of the tools by several feet under favorable conditions and is also effective in promptly freeing the bit from clay or

loose material in the bottom of the hole and in keeping the cuttings in suspension in the well fluid.

With the tools suspended from the crown pulley in the proper position, as determined by "springing" the line as described above, the engine end of the walking beam is raised and the pitman attached to the crank with the wrist pin in the third or fourth hole and with the crank at the top of its arc. With the temper screw gripped in the highest position in its frame, the temper-screw clamps are then firmly attached to the drilling cable, the bull-wheel brake is released and sufficient slack cable is pulled over the crown pulley to prevent jerking the cable above the walking beam as the latter oscillates. The weight of the tools is thus transferred from the crown pulley to the walking beam, and as soon as the engine has been centered all is in readiness for drilling.

The Mechanics of Drilling with the Cable Tools.—The engine is started, and as the beam oscillates, the driller, with his hand on the drilling cable, notes the vibration or "jar" which to the skilled observer indicates the manner in which the tools are operating. Slight adjustments in the position of the temper screw or in the speed of the engine are made until the tools are striking with the maximum force on the bottom of the hole.

Satisfactory progress depends to a large extent upon the ability of the driller to interpret the vibrations that come to him through the drilling cable. The novice sometimes "loses the jar" and works for hours without making any progress. The tools may be standing on bottom while he is playing with the slack in the cable, or they may be swinging several feet off bottom. The skilled driller will know as soon as his hand touches the drilling cable whether the drill is working properly or not.[2]

The jar which the driller feels in the cable is the result of alternate release and application of tension in the drilling cable as the beam rises and falls. Because of the elasticity of the cable, it is probable that the beam is already returning on the upstroke as the tools strike bottom, the result being a distinct jar in the cable as the tools rebound, usually of sufficient intensity to cause vibration of the rig. In addition to the jar, to the sensitive hand of the driller on the cable there is a perceptible reach and lift of the cable as tension is applied and released. As explained above, the tools strike bottom with the cable under tension, the amount of tension depending upon the elasticity of the cable and the extent to which the tools have to reach for bottom. When the tools strike and rebound, the same elasticity causes a contraction of the line, giving the sensation of lift. The action of the tools may be compared with the bounding movement of a small weight churning up and down while suspended on the end of a rubber band. The tools reach down on the stretch of the line and strike a springing blow, rebounding rapidly. As the tools begin to reach for bottom and the "jar works off," the driller "tempers the jar" by lowering the tools with the temper screw.

The speed of the engine and length of stroke of the beam have much to do with the action of the tools. As the well attains greater depth, it is necessary to lengthen the stroke by moving the wrist pin farther from the center of rotation of the crank. For a given length of cable and of stroke, there is a certain periodicity which determines the speed at which the engine should operate. Overspeeding of the engine will result in jerking the tools upward before they strike, subjecting the cable and tools to a destructive strain which often causes breakage of the jars or parting of the

drilling cable. Such action of the tools also induces a jerky motion in the engine until it becomes unmanageable. Catching the tools in this way is one of the common difficulties of the unskilled driller. Too slow a motion, on the other hand, will greatly reduce the force of the blow struck by the tools.[2]

Sprengling and Stephenson have analytically and experimentally studied the motion of the cable tools as influenced by the elastic properties of the drilling cable, the timing and length of stroke and the weight of tools and cable suspended below the beam, and have evolved formulas and graphic data by means of which the natural frequency of the system can be determined. At this speed, maximum efficiency is attained.[18]

Power control becomes increasingly difficult as greater depths are attained. This is a direct result of the greater weight of cable to be lifted and the greater elasticity of the longer cable. This loss of effectiveness of the engine is offset to some extent by lengthening the stroke, or by use of the engine balances on the rim of the flywheel. With an ordinary drilling engine, great skill in steam control is necessary to operate the tools effectively at depths in excess of 2,000 or 2,500 ft. without the use of engine balances. Satisfactory operation of the engine requires a slightly greater speed on the downstroke of the tools than on the upstroke. This results naturally from the alternate release and application of the load on the engine. When balances are used on the engine flywheel, however, a more uniform speed results, which to some extent retards the drop of the tools and compels a slower motion. Hence the use of the engine balances should be avoided until made necessary by the jerky action of the engine.

The action of the tools will vary with the kind of cable used. Hemp cable has greater elasticity than steel and will reach for and strike bottom long after the steel cable under similar conditions will have ceased to strike. The steel cable, when unduly stretched, will often "peg leg," that is, the tools will alternately strike bottom and miss. Hemp cable has more "lift" than steel, a characteristic which, as we have seen, depends upon the elasticity of the cable. Both lift and peg legging are to a great extent dependent upon depth. The remedy is an extension of the temper screw. The action of the tools will also vary somewhat with the amount of water in the hole. Water, of course, retards or damps the motion of the tools, its effect being particularly noticeable in drilling "wet" holes with hemp cable of large diameter. Drilling with the hemp cable requires greater skill on the part of the driller than when steel cable is used.

Opportunity was afforded for observing the effect of elasticity in the drilling cable in one instance where a churn drill hole intersected underground mine workings at a depth of 500 ft. A hemp cable was used with a 36-in. stroke at the walking beam, but at a depth of 500 ft. the actual length of stroke of the tools was in excess of 8 ft. The elastic rebound of the tools also varies markedly with the character of the rock in which the bit is working, being appreciably greater in hard rocks than in semiplastic clays and shales. Because of the reach of the cable in drilling, it is probable that in most cases the hole is actually several feet deeper than the normal length of the drilling cable and tools.

With some types of rocks, best results are obtained by operating the tools "tight hitched," that is, allowing them to strike only on the extreme elastic stretch of the cable. In other cases, "loose hitching" gives best results. The tools should always be tight hitched when drilling through hard, steeply inclined strata because of the tendency of the bit to follow the dip of the strata, thus drilling a crooked hole.

The impact of the heavy cable tools on the bottom of the well when the tools are dropping freely is enormous. Let us assume that a 10-in. hole is being drilled. The weight of the tools will probably aggregate about 3,600 lb. for this size of hole.

The length of stroke or sweep of the walking beam will be, say, 3 ft. Add to this the stretch or spring in 2,000 or 3,000 ft. of drilling cable and we have a total drop for the tools of perhaps 5 or 6 ft. Multiplying the lower figure by the weight of the drilling tools (3,600 lb.), we obtain 18,000 ft.-lb. of work exerted on the formation at each stroke. When it is considered that this impact is repeated at the rate of perhaps 30 strokes per minute on an area of not more than $\frac{3}{10}$ sq. ft. (approximate area of the end of a 10-in. bit), it is apparent that we have to deal with a crushing force of considerable magnitude.

Because of the shape of the end of the bit and the absence of a sharp cutting edge, it is probable that there is comparatively little actual chipping or cutting of the rock, but rather a crushing action which breaks down the rock mass into small fragments. The shape of the disintegrated material will vary with the nature of the rock, being granular in the case of sandstones and amorphous rocks, and platy in the case of thin laminated strata and in rocks possessing well-developed cleavage. The material brought to the surface in the bailer is generally finely pulverized by repeated pounding of the bit on the larger fragments after they are detached from the main rock mass. The walls of the well are probably left rather rough as a result of the action of the bit, and the material in the walls will be badly fractured except in the case of very hard, tough rocks. Because of this, in soft formations the walls tend to cave. The walls are sustained to some extent, however, by the action of clay which accumulates from the sludge between the rough projections on the walls, plastering over the fractures and preventing further disintegration to some extent.

Drilling with the Jars.—In drilling through beds of sticky clay or in caving formations, it is often necessary to bring the jars into play in order to effect release of the bit on the upstroke of the tools. Drilling jars are attached above the stem and usually have a stroke varying from 4½ to 12 in. In drilling, the jars are permitted to telescope for only a part of their maximum stroke, say, for 4 or 6 in. This displacement permits the upper link to gain considerable momentum on the upstroke before picking up the bit and stem. Such action provides the necessary sudden upward jerk to free the bit from sticky material in the bottom. A skillful driller never allows the jars to strike on the downstroke except in certain fishing operations when a jar-down effect is desired.

Rotating the Tools.—In certain kinds of rock, the cable tools have a tendency to drill a flat hole, that is, the well becomes elliptical in cross section. This can result only from the bit striking repeatedly in one position. Since the bit is wider than it is thick, such action is inevitable unless the bit revolves as it operates. Formerly drillers considered it necessary to twist the cable slowly at the temper screw as the tools churned up and down in the well, but the efficacy of this practice is questionable in view of the great length of cable that often exists between the temper screw and the tools. Many drillers insist on the use of a ratchet or swivel type of rope socket, which is supposed to permit of easier rotation of the tools and allows twists in the drilling cable to readjust themselves independently of the tools. An innovation is the use of the spiral-winged drill stem to aid in securing positive rotation of the tools as they rise and fall through the well fluid. It seems reasonable to expect that the spinning of the tools induced by alternate application and release of tension in the cable would be sufficient to prevent the tools from striking repeatedly in the same position except, perhaps, at very shallow depths. If the tools fail to rotate, it is probably due in most cases to loose material accumulating on the bit or on two opposite sides of the hole, and more frequent bailing or a more rapid motion of the tools should remedy the matter.

Flat holes are particularly likely to occur when drilling through water sands. "Tight" holes, which result from loss of gauge by wear on the sides and corners of the

bit, are also characteristic of such material, and for this reason water sands are generally under-reamed. The bits should be frequently redressed if proper clearance for the casing is to be maintained.

Bailing.—Continued operation of the drilling tools results in accumulation of cuttings in the bottom of the well, which will eventually so restrict the motion of the tools that little or no progress is made. Such a condition requires removal of the drilling tools and operation of the bailer.

To "draw out the tools," the bull wheels are first revolved by hand until the slack cable over the crown pulley has been wound on the bull-wheel shaft. The bull ropes are then thrown on, causing the wheels to revolve under the influence of the power and hoisting the tools in the well until the load is transferred from the temper screw to the crown pulley. The driller then promptly throws off the bull ropes and clamps the bull-wheel brake while his helper stops the engine. While this is being accomplished, both the walking beam and the bull wheels are in motion, and, unless the power is disengaged at the proper time, damage to the rig will result.

The temper-screw clamps are then removed from the drilling cable, and the pitman is taken off the wrist pin and lowered to the plank walk. This elevates the end of the beam overhanging the well and places it out of the way of the drilling tools and bailer as they are run into and out of the well. The bull ropes are now again placed in position on the bull wheels and power is applied, raising the tools until they emerge above the derrick floor; the bull ropes are then thrown off and the tools are caught and suspended above the well by clamping the bull-wheel brake when they can be swung over into one corner of the derrick.

Manipulation of the sand-reel reach draws the friction pulley forward against the face of the band wheel, thus causing the sand reel to revolve and lifting the bailer until it swings freely above the derrick floor. Reversing the position of the reach causes the friction pulley to bear against its brake post so that the bailer can be held suspended in any desired position. The lower end of the bailer is guided into the well, the brake is released and the bailer is allowed to descend rapidly, braking occasionally, until bottom is approached, when the descent is brought under close control by further application of the brake.

The bailer is raised a few feet and lowered to bottom several times to make certain that coarse material accumulated near the bottom has had ample opportunity to pass the bailer valve. It is then withdrawn as rapidly as possible by bringing the sand-reel friction pulley to bear against the face of the revolving band wheel. On reaching the surface, the bailer is suspended with the lower end a little above the derrick floor by shutting off the power and applying the brake. The loaded bailer is then swung to one side from its position over the well and lowered (by partly releasing the brake) through a hole in the derrick floor into a wooden trough placed immediately beneath. As the bailer valve is raised by downward pressure of the dart on the bottom of the trough (or by a metal rod mounted vertically in the trough in the case of disk valve bailer), the content of the bailer flows out and may be inspected to determine the nature of the material. The power is then applied, raising the bailer until it clears the derrick floor, when it may be swung over into one corner of the derrick and held out of the way by a metal hook or rope sling, or it may be lowered into the well for another load of sludge. Usually several trips to bottom with the bailer will be necessary before the well will be sufficiently cleared to resume drilling operations. The process of lowering the tools and of attaching the temper screw as described above must then be repeated.

Replacing a Worn Bit.—Continued use dulls the cutting edge and corners of the bit and reduces its gauge so that it no longer drills a hole of the desired diameter. It must therefore be occasionally replaced with a properly dressed and gauged bit.

When slow progress warns that the bit has become dull, the tools are drawn out as described above under "Bailing." As the tool joint between the drill stem and the bit emerges from the well above the derrick floor, the power is shut off and the tools held suspended (with the bit in the well) by clamping the bull-wheel brake. The tool joint is loosened by application of the circle jack and the power again applied until the bit swings free above the derrick floor. The bit is then unscrewed from the stem with the aid of hand wrenches if necessary, and a fresh bit is screwed to the stem in its place. The heavy bits are conveniently supported, before attaching to and after disengaging from the stem, by means of a swivel wrench hung horizontally, suspended on chain blocks from a derrick crane (see Fig. 63). Such a crane can be swung to any

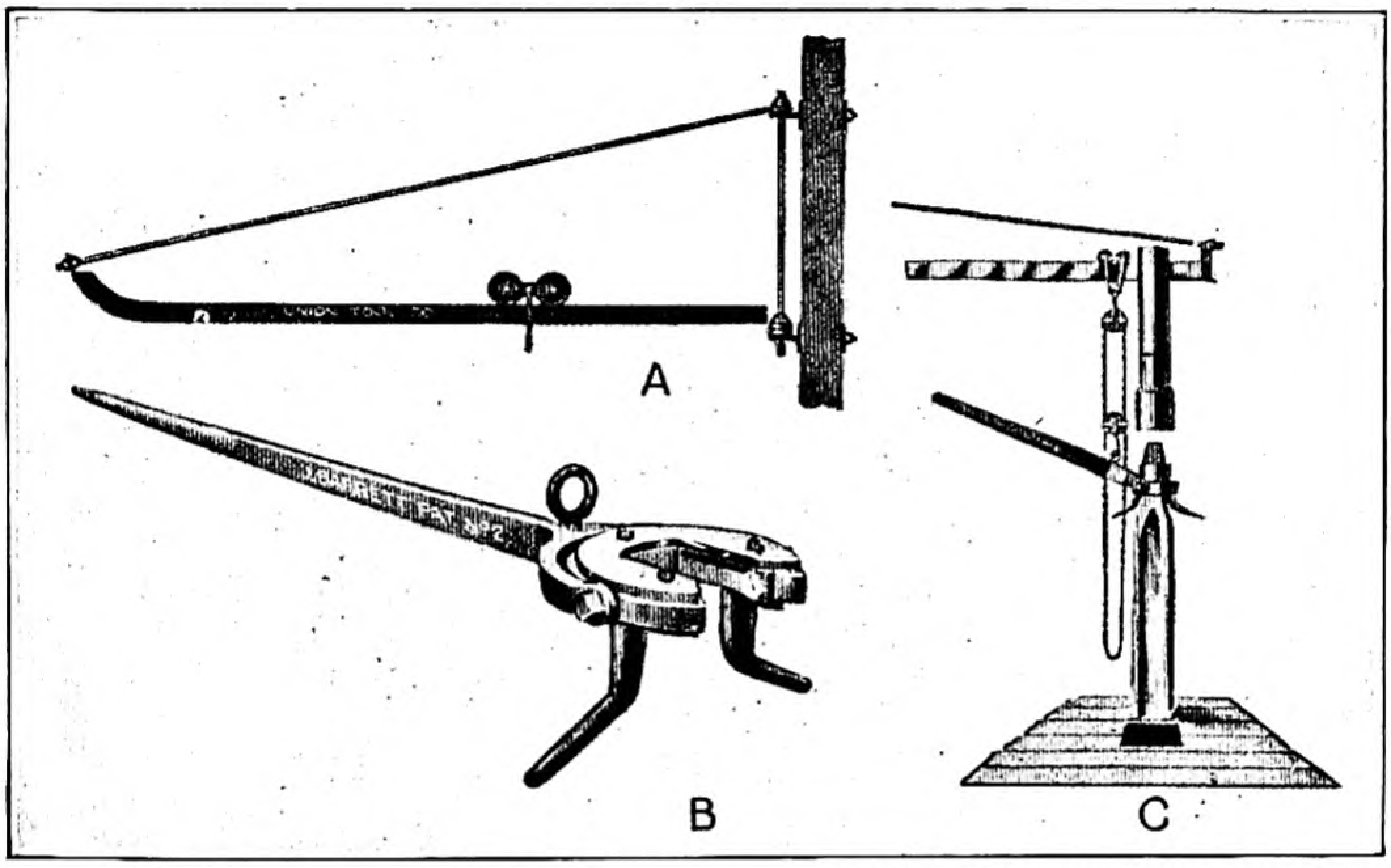


FIG. 63.—Derrick crane *A* and swivel wrench *B* for supporting drilling bit *C*.

desired position over a radius of 10 ft. from the post in one corner of the derrick to which it is attached. The wrench supported on its chain hoist is suspended from a small two-wheeled trolley which may be moved to any desired position along the horizontal beam of the crane. On lowering the sharpened bit into the well, the tool joint connecting it with the stem is "set up" with the aid of the circle jack.

The Routine of Drilling with the Cable Tools.—Unless some accident occurs to interfere with the operation of the tools, the routine of the work becomes rather monotonous. The equipment is usually operated day and night, with either two or three crews of men working 12 or 8 hr., respectively. Each crew consists of two men, the driller, who is in responsible charge of the work, and his helper or "tool dresser." The work is divided into alternate periods of drilling and bailing, with occasional interruptions to insert casing (see Chap. XI).

The frequency of bailing depends upon the nature of the material in which the drill is working. Frequency of bailing also depends upon the rate of progress and the extent to which the material loosened by the bit remains in suspension in the well fluid. Certain kinds of clays and soft

clay shales require frequent bailing, perhaps for every 2 or 3 ft. of progress. In hard rocks, on the other hand, the hole may be advanced for several lengths of the temper screw without necessity for bailing.

If it is unnecessary to bail when the full length of the temper screw has been let out, the engine is stopped and the weight of the tools is transferred to the crown blocks (as described under "Bailing"), while the temper-screw clamps are loosened from the cable and the screw is raised for a new grip on the cable. The clamps are then attached in the new position, the weight is transferred back to the beam (as described under "Hitching On") and drilling is resumed. The temper screw can ordinarily be extended about 5 or 6 ft., so that the procedure outlined for taking a new hold on the cable need be repeated only at this interval.

Unless water enters the well from the formations penetrated, sufficient must be poured in at the surface to form a thin sludge with the material loosened by the drill. Practice differs as to the depth of fluid maintained in the well. In "dry-hole" drilling, as commonly practiced in the fields of the Eastern United States and in some of the Mid-Continent, Texas and Rocky Mountain fields, only sufficient water is used to keep the drill cuttings from clogging the bit; but in some of the California fields the hole is maintained full or nearly full of water, to aid in preventing the walls from caving. Dry-hole drilling is preferable since the tools develop their maximum efficiency when movement is not impaired by friction of the drilling cable on a long column of water, and by the buoyant effect on the tools; but where the walls have a tendency to cave, or where "heaving" formations are to be penetrated, the pressure of a long column of water is of considerable assistance. Long strings of heavy casing may also be more readily handled in a hole full of water.

The Speed of Drilling.—The number of strokes per minute at which the drill can be operated will depend upon the depth of the well, the diameter, the depth of fluid in it and the nature of the material in which the bit is working. Generally speaking, great depth, small diameter, great depth of fluid or soft material necessitates a slow motion. The number of strokes per minute will ordinarily range between 20 and 40.

The rate of progress in cable drilling will vary within wide limits. Varying character of the formations penetrated, the depth of the well, its diameter and time lost in inserting casing and cement and in fishing operations are important variables that influence the rate of progress. In soft rocks at shallow depths, an advance of 100 ft. or more may be made in a 24-hr. day, under favorable conditions. In a hard layer of "shell" (any hard rock), 5 ft. of hole may represent a good day's work. The rate of progress also depends largely upon whether or not the walls stand without caving and whether the material penetrated tends to heave or flow into the well. The depth of the well influences the rate of progress

in two ways: in a deep well, the tools do not work so satisfactorily and must be operated at a slower speed, and more time is consumed in drawing out and lowering the tools and bailer. The tools do not drop so freely in a hole of small diameter, particularly if it is filled with water. Hence a slower drilling speed must be adopted and progress is slower. Any interruption in the usual routine of drilling, of course, greatly influences the average footage drilled per day. Casing may have to be underreamed or driven past tight places in the hole. Breakage of the tools or parting and collapsing of the casing may necessitate a fishing job of several days' or even weeks' duration, during which no increase in depth

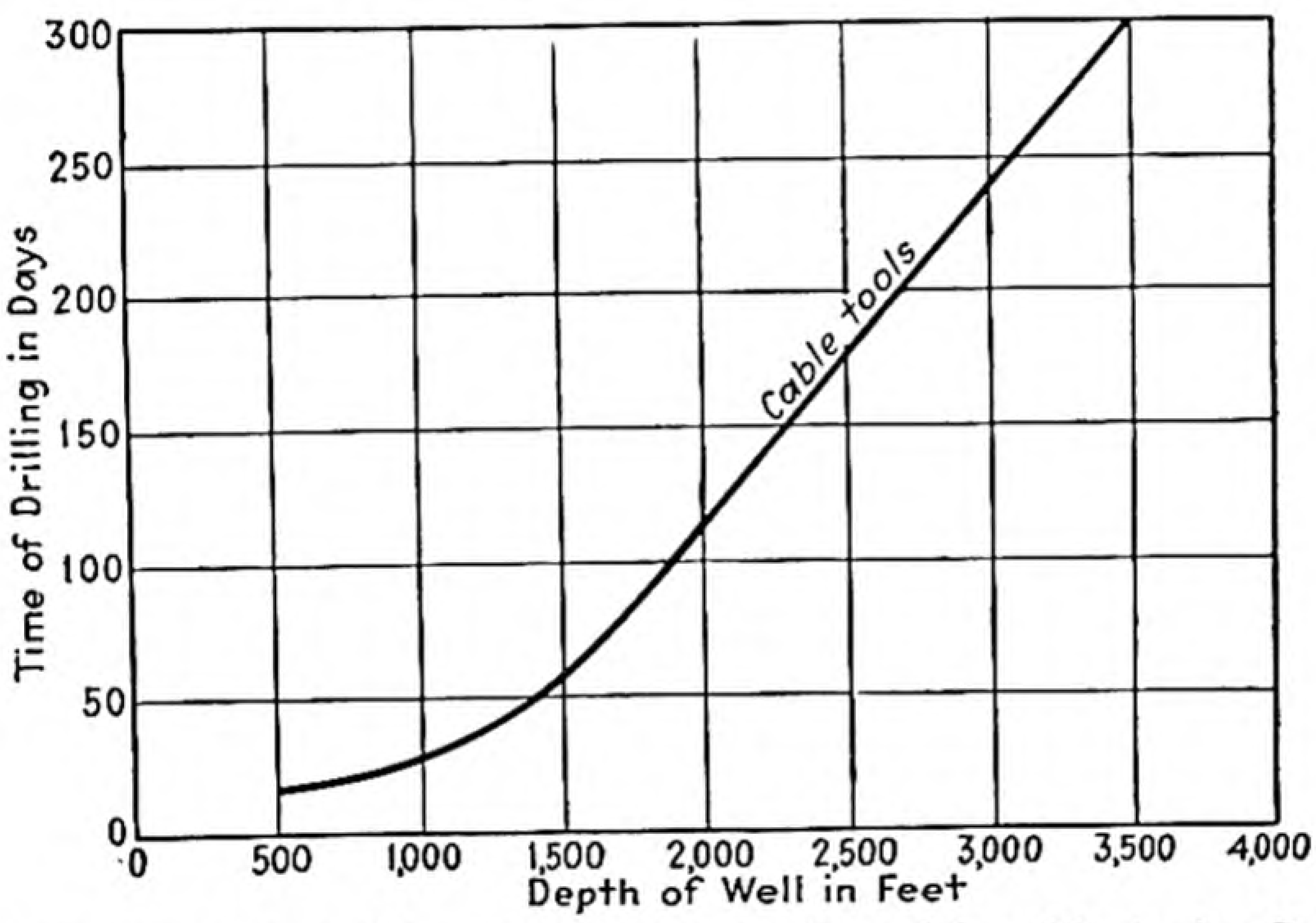


Fig. 64.—Time consumed in drilling to various depths with cable tools, California fields.

is attained. When cement is introduced into the well to exclude water, an interval of at least several days is allowed for the cement to set and harden before drilling is resumed.

In the San Joaquin Valley fields of California, a region characterized by comparatively soft formations, up to moderate depths (say, 1,500 ft.) progress will average about 30 ft. per day with a maximum of 60 to 70 ft. and a minimum of 5 ft. At depths in excess of 3,000 ft. in the same region, 15 ft. per day is a good average rate of progress, with about the same minimum and a maximum of, say, 30 or 40 ft. In a 1,350-ft. hole drilled in the black shales and lime of north central Texas—an unusually hard formation—progress averaged 27 ft. per day, a high average for this kind of rock. The graph reproduced in Fig. 64 indicates average rates of drilling for cable tools in the San Joaquin Valley region of California.

CABLE-TOOL CORING DEVICES

When better samples are desired of the formation in which the drill is working than are afforded by the drill cuttings brought to the surface

by the bailer, recourse may be had to the use of a cable-tool core barrel. This is a special drilling tool which is run below a set of jars in place of the usual drilling bit. Figure 65 illustrates two successful types of cable-tool core barrels. The Baker core barrel, illustrated in Fig. 65*A*, consists of two main parts: an outer drilling barrel and an inner core-retaining tube. The drilling barrel is composed of three essential parts: a drill-barrel head *A*, a drill barrel *B*, and a drill-barrel shoe *C*. The core-retaining tube is also composed of three parts: a core-tube head *D*, a core tube *E* and a core-tube trimmer shoe *F*. In action, the lower end of the core-retaining tube rests in a stationary position on the bottom of the well, while the outer barrel churns up and down about it as a guide, striking bottom on each downward stroke. Circulation holes *G* are provided, leading inwardly to a chamber within the drill-barrel head, which is closed at its lower end by a back-pressure valve *H*, which opens downward. This valve opens on the upstroke of the drill, permitting the well fluid to enter the barrel. This valve action confers an hydraulic effect upon the water within the outer barrel on the downstroke, causing it to flow down into the core-tube head, whence it escapes through ports *I* into the annular space between the drill barrel and the core tube and out into the well between the core tube and the drill-barrel shoe. This circulation of fluid between the inner and outer barrel prevents clogging and keeps the bit free of the barrel. A second valve *J* of ball-check type is used in the top of the core tube to prevent circulating water from entering the core tube and yet permit fluid contained within the core tube to escape as the core enters. This valve is firmly seated on the downstroke by the downward hydraulic pressure and is held in position by gravity on the upstroke. The drill-barrel shoe is made with a clearance at the cutting edge to allow the barrel to drop freely in the hole. The cutting teeth are spaced irregularly and are faced with a hard facing metal. It is connected to the lower end of the drill barrel with a special tool-joint thread, and, being smaller than the inside diameter of the drill barrel, a shoulder is formed which prevents removal of the inner core-retaining tube. The latter has a shoulder at its upper end. The core-tube trimmer shoe is screwed on the core tube and is made with a sharp-beveled edge, which is faced with hard facing metal. A tapered, split trap ring *K* is mounted on the inside of the trimmer shoe.

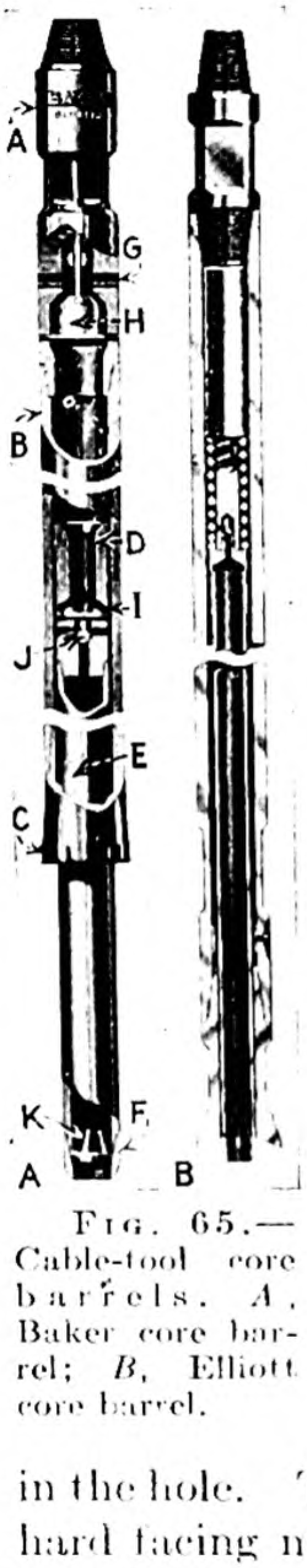


FIG. 65.—Cable-tool core barrels. *A*, Baker core barrel; *B*, Elliott core barrel.

Figure 65*B* is illustrative of the Elliott cable-tool core barrel. This

device also makes use of an inner core-retaining barrel, which is supported within an outer drilling barrel. The bit is of star form and is of special heat-treated steel. The inner barrel is of seamless tubing, 10 ft. long, and supports a special shoe and core catcher at its lower end. A slender retaining ring attached to the inner wall of the outer barrel prevents the inner barrel from falling out when the tool is being lowered or raised into or out of the well. A valve, mounted on the upper end of the inner barrel, permits escape of the well fluid as the core enters. Above this are a spring and an adjustable weight. In operation the inner shoe remains on bottom, while the outer barrel and bit rise and fall with the motion of the beam. As the hole is deepened, the inner core barrel is driven down over the core. On withdrawing the tool, the core catcher grips the core and prevents it from falling out.

The cable coring tools should be operated in at least 30 ft. of fluid and with a somewhat slower motion than is usually employed when drilling with the ordinary bit, and the stroke used must not be so great that the core barrel is raised off the bottom of the hole. From 4 to 7 ft. of core may be cut at one time, but best results are obtained by not exceeding 5 ft. The cores are seldom in long sections as is the case with diamond drill cores but are customarily in "biscuit" form, or in short cylinders ranging from ½ to 2 in. in thickness. The cost of coring with the cable tool ranges from as little as 40 cts. to $4.75 or more per foot. Upward of 95 per cent of the footage drilled may be recovered as core under favorable circumstances. Cable-tool core barrels have been used in recent drilling in the Appalachian and Rocky Mountain fields of the United States.

PORTABLE AND SEMIPORTABLE RIGS FOR CABLE DRILLING

For prospecting work, and for drilling wells in shallow territory—even up to depths of 2,500 ft.—portable and semiportable drilling machines are often used. These are much lighter than the standard cable rig described in the foregoing pages but operate on the same principle and often by quite similar equipment. Instead of a derrick, these portable rigs are generally equipped with a braced mast and the machinery is mounted on a four-wheeled truck or on a light timber-frame structure that can be readily moved about as a unit from one location to another and put in condition for active service within a few hours' time. The trucks are sometimes of the self-tractor type so that they can be moved about under their own power.

Each part of the standard cable rig has its counterpart in most of these portable rigs, often changed in form and size, however, to adapt it to use in a smaller space and to render it more readily transportable. There is necessarily some form of a walking beam or spudding device to impart the churning motion to the drilling cable. There must be two hoisting drums

on which the drilling cable and sand line are wound, and there must be a source of power with means of distributing it to the different parts of the rig. Some of the heavier rigs are equipped with an additional drum for handling casing. Usually, however, the drilling cable is used for handling casing. A steam engine and boiler furnish the power in many cases, though frequently a gasoline engine will be used. The latter type of engine is simpler as a power unit, and occupies less space, but is not so well adapted to the work of drilling as the steam engine. The drilling tools and incidental equipment are quite similar to those used in connection with the standard cable outfit, except that they are usually smaller and lighter.

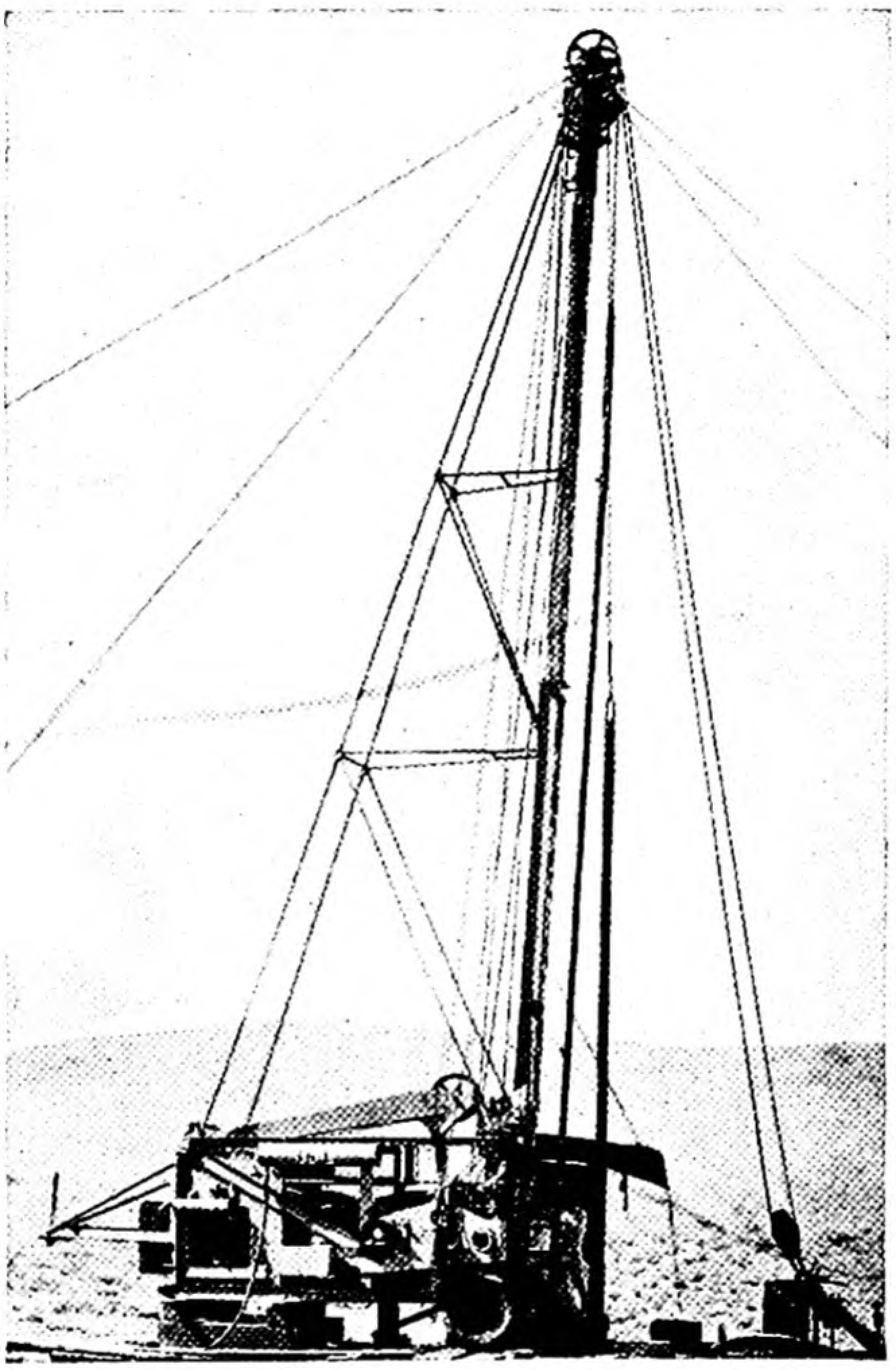
Probably the greatest difference to be noted in the several types of portable and semiportable rigs is found in the design of the mast. The mast serves the same purpose as the derrick and must therefore provide a support at a suitable elevation for the sheaves used in changing the direction of the drilling cable, sand line and casing line. Two types of masts are in common use: (1) the single-post mast, which consists of a single heavy timber mounted on end on the ground or on one end of the truck on which the machine is mounted; and (2) the two-legged braced mast, built of metal channels latticed together, or of two heavy timbers, suitably braced by horizontal girts and mounted on the sides of the truck. In some cases the mast is entirely independent of the drilling mechanism. It is often built in sections to facilitate transportation, the sections being readily assembled and disassembled. The braced mast can be built of lighter material than a single-post mast of the same strength and, if properly designed, should be more rigid. In either case the mast is slightly inclined from the vertical to bring the sheaves at the top clear of the supports and must be braced with guy wires in several directions to near-by stakes driven in the ground.

Among the many drilling machines in use, the Bucyrus-Erie and Star drilling rigs are well known among the portable machines, while the National rig is a well-known semiportable type. A brief description of each of these will serve to acquaint the reader with the main features of portable and semiportable drilling equipment. The reader is referred to the manufacturers' catalogues for more detailed information on these and other rigs.

The Bucyrus-Erie Spudder.—A spudding machine is equipped with a crank-operated rocker carrying a floating sheave, under which the drilling cable is passed. In operation, the cable is thereby given a reciprocating motion that provides a quick, almost free drop of the tools and a slowly accelerated lift. The machine also incorporates a hoisting drum or winch on which the drilling cable is wound, a calf reel for handling casing and other heavy loads and a sand reel for bailing. Power is furnished by an internal-combustion engine, mounted integrally with other elements of the rig and all necessary controls, in a framework of steel on metal skids. The Bucyrus-Erie spudder, a well-known type, is designed for drilling with cable tools to depths as great as 3,000 ft. Model 36-L, pictured in Fig. 66, is powered with a

128-hp. engine and is capable of handling 7,000 lb. of tools and drilling cable and of lifting 27,800 lb. at reduced speed. The chain-driven sand reel will lift a 7-in. by 30-ft. bailer from a depth of 3,000 ft. in 3½ min. The unitized elements of this rig are permanently mounted in an all-steel, electrically welded and trussed flat-bottomed frame that facilitates skidding on or off trucks or platforms. This rig also carries an all-steel power-raised telescoping derrick.

The Star portable drilling machine is made in a variety of sizes, all mounted on four-wheeled trucks, the heaviest model (No. 30) being rated by the manufacturers for



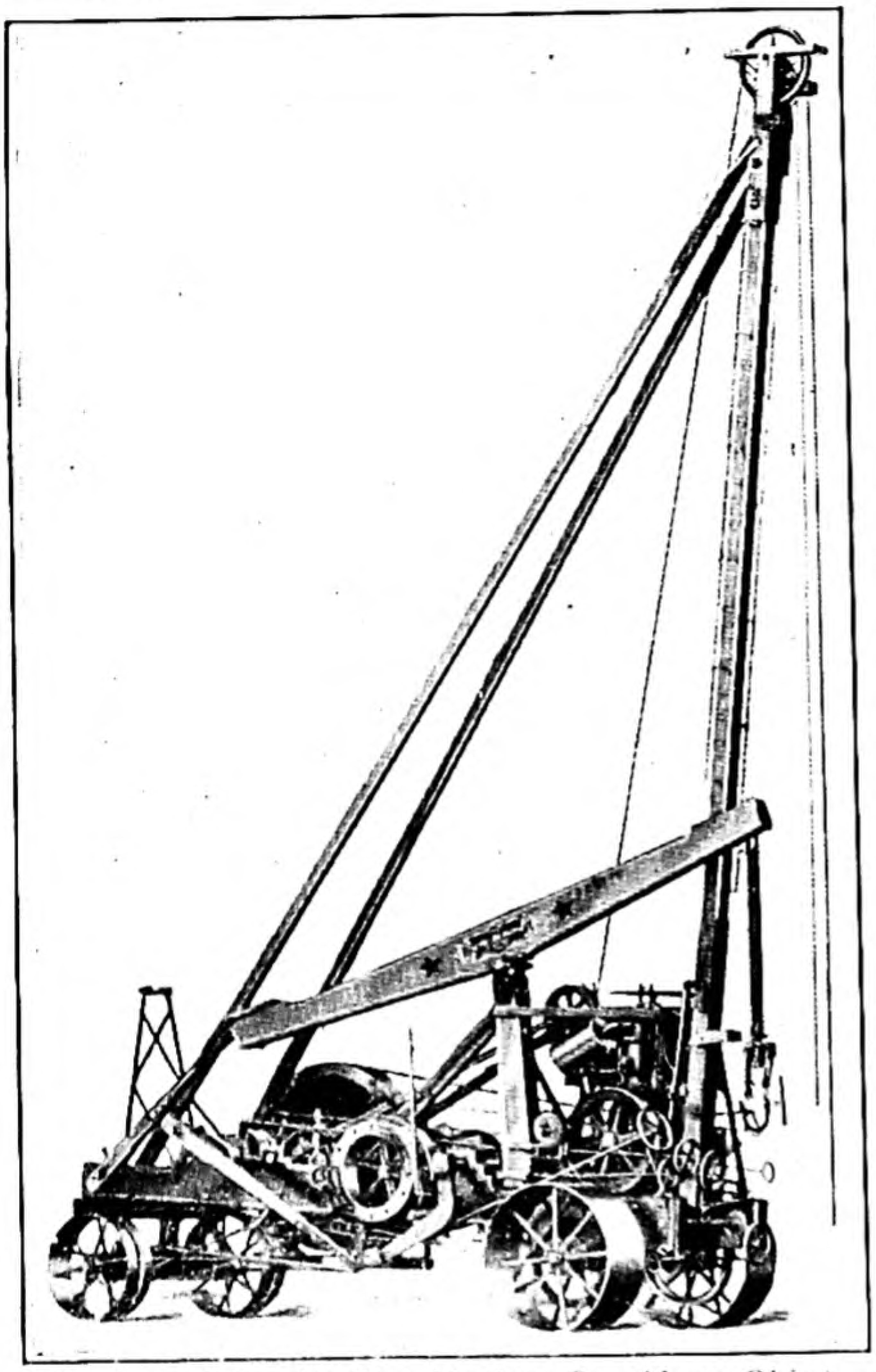
(Courtesy of Bucyrus-Erie Co.)

FIG. 66.—Bucyrus-Erie portable cable-tool spudder.

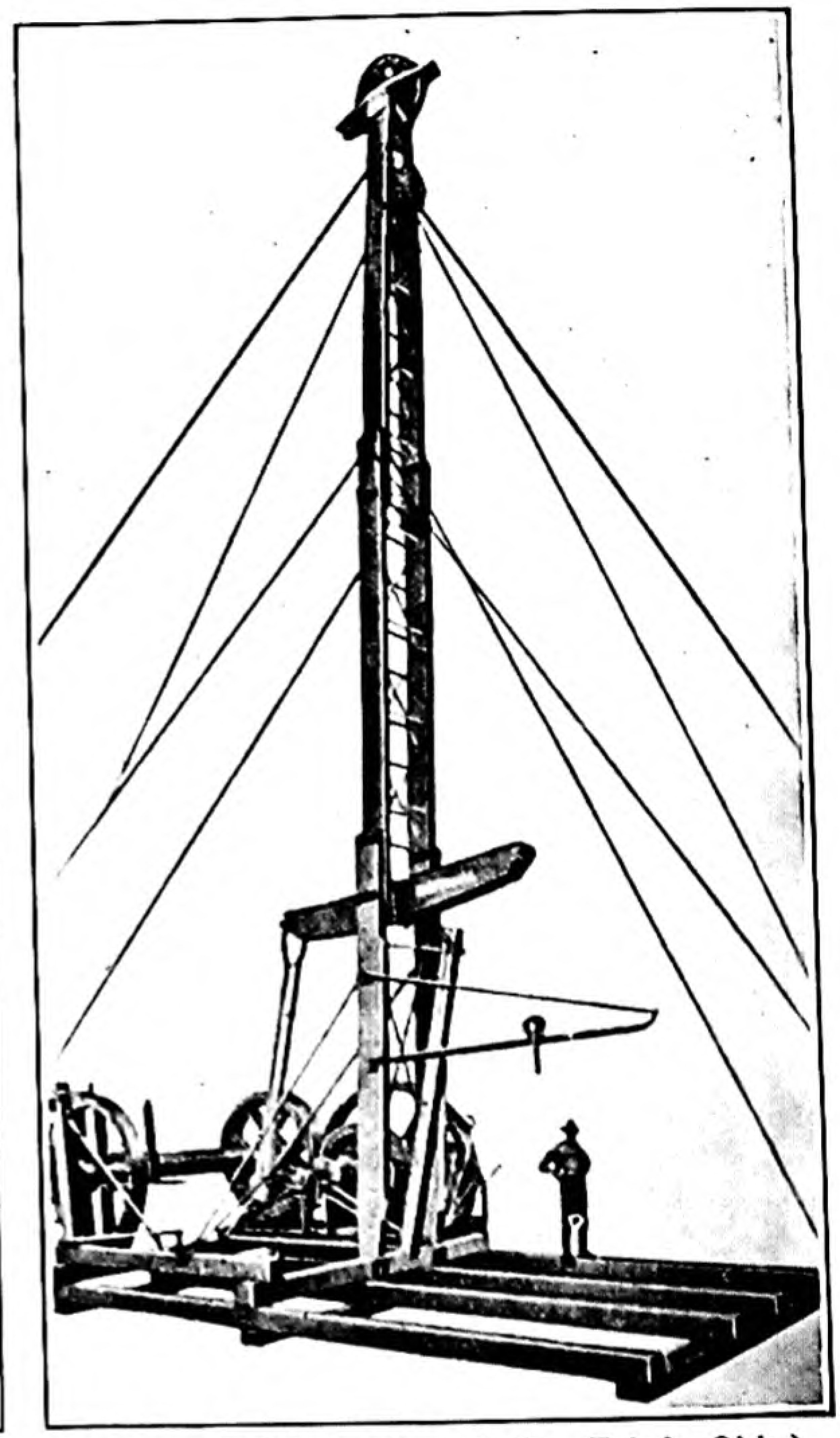
drilling to depths as great as 4,000 ft. The heavier models are all equipped with vertical reversible steam engines and boilers, but several models equipped with gasoline engines are also available for drilling to depths of less than 1,000 ft. The latter are of the self-tractor type.

The No. 30 Star machine (see Fig. 67), widely used in earlier years, is equipped with a 60-ft., single-pole timber mast, sectionalized to facilitate transportation, with additional shear poles provided for bracing the mast when very heavy lifting is necessary, and 12 guy wires. Three pulleys are mounted on or near the upper end of the mast to support the drilling cable, sand line and calf line. A walking beam 22 ft. long is mounted on a slanting samson post at one corner of the truck and heavily braced to one side. The 35-hp. steam engine is mounted at the same end, a belt

connecting from its flywheel to a 92-in. wooden band wheel, mounted on one side of the truck and serving as a power-distribution center for the entire machine. In the case of the model 30, the boiler is mounted on a separate wheeled truck, but in smaller sized machines it is carried on the end of the same truck that supports the drilling machinery. A crank mounted on the band-wheel shaft operates the walking beam through a connecting wrist pin and pitman. The 60-in. bull wheel or drum, supported at the center of the truck and driven by gearing from the band-wheel shaft, is equipped with a reel large enough to spool 2,500 ft. of 2¼-in. hemp cable, and with



(Courtesy of Star Drilling Machine Co., Akron, Ohio.)
FIG. 67.—Star portable drilling machine.



(Courtesy of National Supply Co., Toledo, Ohio.)
FIG. 68.—National semiportable drilling rig.

a heavy band brake. A sand reel driven by a belt from a countershaft, operated by a friction pulley bearing on the face of the band wheel, actuates the bailer. A calf wheel for handling casing is also built into the machine. This is operated by gearing from the band-wheel shaft. Instead of suspending them from a temper screw on the end of the walking beam, the drilling tools may, if desired, be operated by a spudding attachment mounted in a slot on the crank.

The weight of the No. 30 Star machine complete with boiler and tools is about 52,000 lb., too heavy to move without partly dismantling except on very well-built roads. The main frame of the truck is 6 ft. wide by 23 ft. long. It is claimed by the manufacturers that this machine is the equal in every respect of a heavy standard cable rig, being capable of handling the same-sized tools and an equal weight or length

of casing. The model 30 machine described above is used less than the lighter and medium-sized machines designed for shallower depths. Some of the lighter rigs weigh only 7,000 lb. One commonly used medium-sized machine (No. 26), designed for drilling to 2,200 ft., weighs about 27,000 lb., and with tools and incidental equipment about 35,000 lb. One well 2,825 ft. deep was drilled with a No. 26 machine in 45 days.

The National semiportable drilling rig resembles more closely the ordinary standard cable rig than do the machines mounted on wheeled trucks described above. The chief difference in comparison with the standard rig lies in the use of a braced, two-legged mast instead of a derrick and a more compact arrangement of the rig wheels and parts. The rig wheels and controls are mounted on a bolted wooden frame and are of such weight and so compact that the whole machine can be placed on a truck and moved as a unit from one location to another. The mast is built in sections which can be readily dismantled or assembled. The walking beam, instead of being mounted on a samson post, is supported on trunnions between the two legs of the mast. The machine is built in two sizes: No. 1 for drilling to a depth of 1,600 ft. and for handling a 17,000-lb. string of casing and No. 2 for drilling to 2,500 ft. and handling 30,000 lb. of casing.

The No. 2 machine is illustrated in Fig. 68. Power is received from an engine (not a part of the equipment) by belt on a wooden band wheel 10 ft. in diameter. Both the 7-ft. bull wheels and the sand reel are operated by a wooden friction drum 5 ft. in diameter with a 16-in. face, mounted on the band-wheel shaft. A hoisting drum for handling casing, which can be adapted to the rig if desired, is operated by a chain-and-sprocket drive from the end of the band-wheel shaft and is equipped with a clutch and a heavy band brake. The braced mast is about 65 ft. high and is made up of 12-in. 20.5-lb. channel steel, suitably braced and built in three sections. Timber masts of similar design may also be had if preferred. At the upper end of the mast, a 43-in. crown pulley is supported and smaller sheaves are provided below for the sand line and casing line. The mast is hinged to one of the oak sills for convenience in hoisting it into position, the power being used to assist in this operation. The walking beam, supported between the mast legs, is operated by a pitman attached by a wrist pin to the crank mounted on the end of the band-wheel shaft. The beam is considerably shorter than that provided in the standard cable rig. This method of supporting the walking beam and the friction drive used for operating the bull wheels are the distinctive features of the National rig.

Advantages and Disadvantages of Portable Rigs.—The portable rigs have certain well-defined advantages and limitations. For drilling in shallow territory, the cost of the well may be materially reduced since there is no necessity for the building of a derrick or other expensive fixed surface plant. Shallow wells can often be operated in multiple with a simple pumping jack at each well, and such repairs as are necessary after the well becomes a producer may also be handled by a portable pulling outfit mounted on a truck. Under such conditions the portable rig has become a serious competitor of the standard rig. For prospecting work, where the formations to be tested are within reach of the portable machines, they have the great advantage of ease in transportation. They are more readily dismantled and reassembled and therefore have a relatively greater salvage value after drilling a dry hole.

One of the serious disadvantages of most of the portable rigs is found in their inability to handle satisfactorily the heavy strings of casing necessary in drilling through unconsolidated sands and caving formations. In many regions where the tools can be operated in uncased holes to great depths this limitation is of course not a serious matter. Some of the manufacturers, in striving to adapt their machines to more difficult conditions, are giving attention to this phase of the work and have added calf drums which, while mechanically weak in most cases, are a step toward a real solution of the difficulty. Another disadvantage in comparison with the standard rig is the relatively short stroke of the walking beams or spudding devices provided in most of the portable machines. The beams are usually from 2 to 6 ft. shorter; and at depths greater than 1,500 ft., when stretch in the cable becomes a factor of importance, the effective stroke of the tools becomes so short that the portable rig is much less efficient. Though some of these rigs are rated by the manufacturers for depths in excess of 3,000 ft., it is doubtful if many operators would undertake the drilling of a deeper hole than this with a portable rig. The principal field of most of the portable rigs, as at present designed, would appear to be in drilling wells in formations that do not cave readily and to depths not greatly in excess of 2,500 ft.

THE STANDARD CIRCULATING SYSTEM OF DRILLING

In an effort to devise a means of drilling through unconsolidated sands and caving formations of the California San Joaquin Valley fields to depths of more than 3,000 ft. with cable tools, and to reduce the number of strings of casing necessary in so doing, the so-called "circulating system" of drilling was developed. This method involves the use of the complete standard cable equipment and, in addition, a pair of high-pressure slush pumps such as are used in rotary drilling, with flexible connections to a "circulating head" supported by a massive "swinging spider" on which the casing in the well is suspended (see Fig. 69). The purpose of the additional equipment is to provide a means of "mudding" the soft material in the walls of the well so that it does not cave about the casing, a process commonly employed in rotary drilling (see Chap. VIII). Mud-laden water is pumped down through the casing, passes under the casing shoe, which is lowered as the bit progresses, and back to the surface in the annular space between the casing and the walls of the well. In order to keep this space clear, the casing is frequently raised for a few feet and lowered with the swinging spider, which is supported by a large hook and hoisting block strung on the casing line from the derrick crown block. The circulating fluid, in addition to mudding the walls of the well so that they do not cave, serves to lift a part of the material loosened by the drill so that less bailing of the well is necessary.

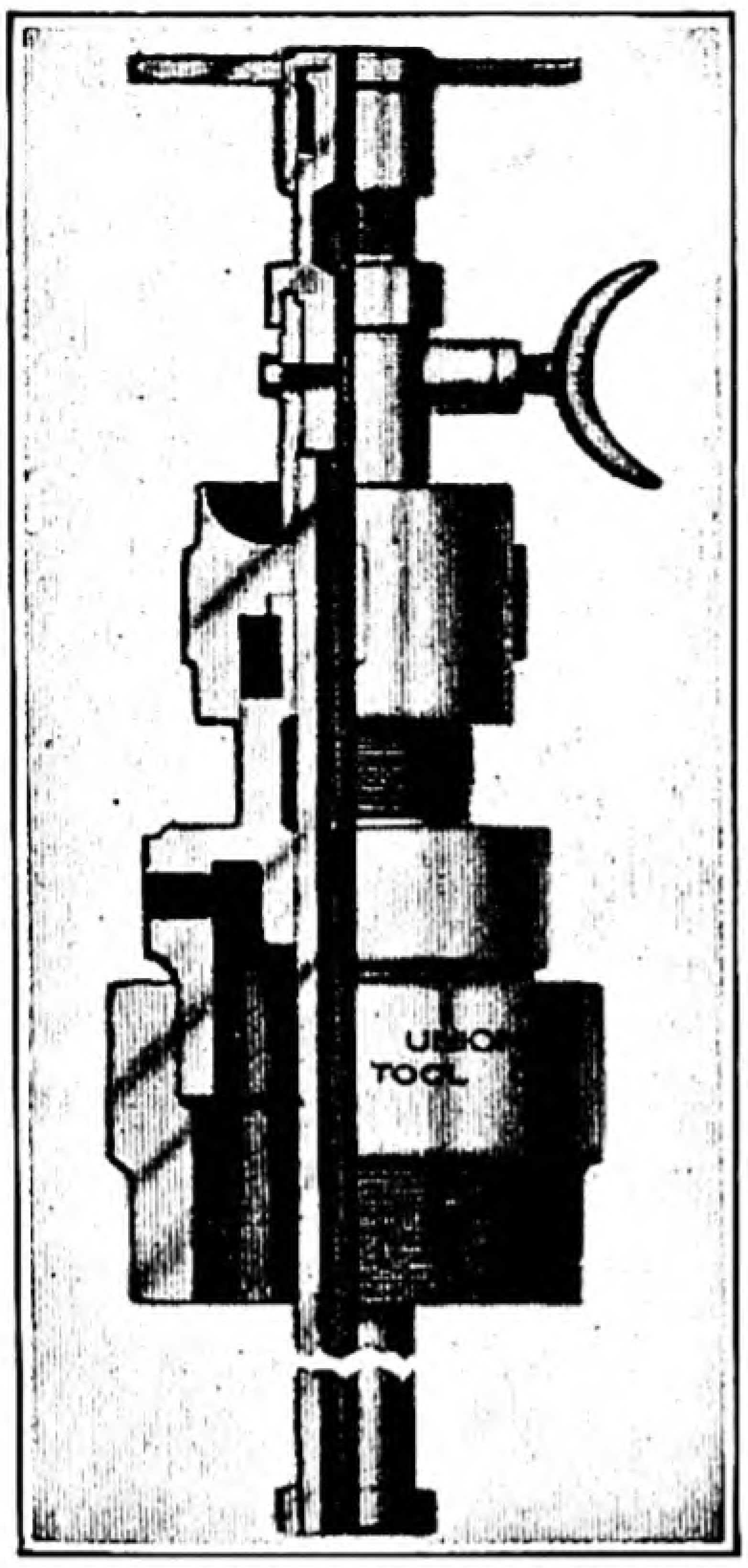
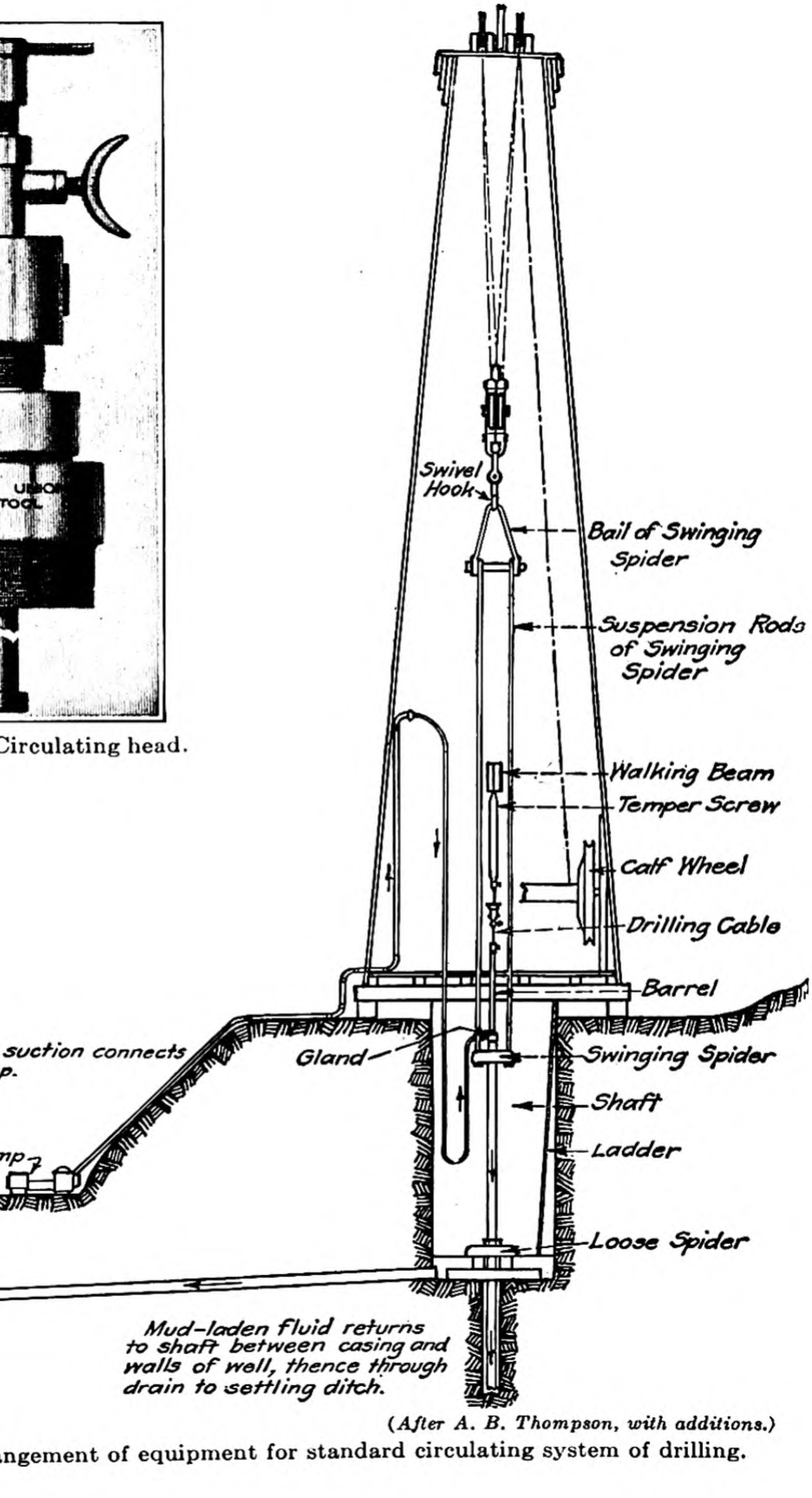


FIG. 69A.—Circulating head.



(*After A. B. Thompson, with additions.*)

FIG. 69.—Arrangement of equipment for standard circulating system of drilling.

The cable tools operate in the usual manner, except that the drilling cable works through a stuffing box in the circulating head, which prevents leakage of the mud-laden fluid as it is pumped down through the casing. The stuffing box is so designed that it does not seriously interfere with the lowering and withdrawal of the drilling tools (see Fig. 69*A*). A polished plunger is fastened around the drilling cable by means of rope clamps, which on being released allow the cable to be drawn from the well through the circulating head until the rope socket emerges from the well. The bolts which fasten the stuffing box in the circulating head are then loosened and the entire top of the head with the polished plunger and stuffing box is lifted out with the tools, leaving the full cross section of the casing free for bailing or other operations. In lowering the tools into the well to resume drilling, the top of the circulating head is bolted in position as soon as the tools have entered the casing, but the plunger is not clamped to the cable until the tools have reached drilling position at the bottom of the well and have been hitched to the beam.

The temper screw plays between the two reins of the swinging spider, which are about 40 ft. long. The cellar should be about 30 ft. deep and of ample size to permit of proper manipulation of the swinging spider. At the cellar bottom a stationary casing spider is placed, which supports the pipe in the well when a new joint is added. The column of casing in the well is raised and lowered with the swinging spider at intervals of from 10 to 20 min. without interruption in drilling. The pumps connect with side openings in the circulating head through armored hose. Returns from the well flow through a trough in which the coarse sand settles, to a mud pit where the fluid is taken in by the pump suction lines for repeated circulation through the well.

It is important, when this system of drilling is used, to maintain ample clearance between the casing and the walls of the well, thus eliminating danger of sand lodging around the pipe and interfering with circulation of the well fluid or of freezing the working string of casing. An unusually heavy casing shoe is employed and all hard formations are underreamed until the casing can be lowered freely. Also, the casing used is somewhat smaller in diameter than the casing normally employed in a hole of the size drilled. When a conductor pipe is landed, the clearance necessary to maintain circulation of the well without the application of abnormal pressure is obtained by skipping one size of pipe in the usual series of telescoping sizes; thus, a 10-in. casing may be used inside of a 15½-in. conductor string instead of a 12½-in. one. It is usually important to maintain fairly continuous operation of one or another of the two pumps. A shutdown of more than an hour or so may result in settling of the mud and cause freezing of the casing or loss of circulation.

This method of drilling has been given a sufficient trial in the oil fields

of California to prove definitely that it is practical and that it has certain advantages over the ordinary cable drilling method in drilling through unconsolidated caving formations. The most important advantage is that, by the use of it, strings of large-diameter pipe can be carried to unusual depths without danger of freezing. This often results in the saving of one or more strings of casing and leaves a larger available working diameter in the bottom of the well. Better drilling time results from the absence of casing difficulties and because bailing is not so frequent an interruption. Through the use of the circulating mud-laden fluid, better control of high gas, oil and water pressures is afforded. Although the additional equipment necessary is costly, the added expense is offset by the saving in casing and more rapid progress.

Notwithstanding the demonstrated advantages of this method of drilling, it is now rarely if ever used because the rotary method has been found cheaper and even better adapted to the conditions against which it was designed to contend. Yet, during its period of development, a considerable number of wells were successfully drilled by this method, and the records made with it compare favorably, except for the greater cost, with those achieved by the more modern rotary equipment. In one well a 15½-in. string was set at 2,300 ft. and a 12½-in. string through this at 3,003 ft. In another well, the 15½-in. string was set at 2,100 ft. and a 10-in. string at 3,300 ft. In each case the casing was entirely free in the well, though previous drilling in the same territory by ordinary standard cable methods had shown that the walls could not be maintained for more than 40 or 50 ft. ahead of the pipe.[8]

COST OF CABLE DRILLING

The cost of drilling with cable tools varies widely in different regions, being dependent to an important extent upon accessibility, depth and character of the formations to be penetrated, prevailing wage scales and other related factors. Fluctuation in the purchasing power of the dollar during the past twenty years has also been responsible for wide variation in drilling costs. Within recent years, contracts have been let for the drilling of wells to depths of less than 1,500 ft. through the hard formations overlying the oil sands in the northern Pennsylvania region for less than $1 per foot. These wells were drilled with semiportable rigs such as that illustrated in Fig. 68, and the contractor furnished everything necessary for the drilling of the well except casing and the gas used in developing power. Contract prices for cable-drilled wells in the Texas and California fields, on the same basis, using standard rigs, have been in many cases in excess of $5 per foot. For deeper drilling by cable methods in Western American fields costs have been as high as $17 per

TABLE XVIII.—COST OF DRILLING WELLS WITH CABLE TOOLS

	Well No.											
	1		2		3		4		5		6	
Field	Ranger, Tex.		Desdamona, Tex.		Caddo, La.		Lost Hills, Cal.		Coalinga, Cal.		Sunset, Cal.	
Year drilled	1919		1919		1919		1920		1920		1920	
Depth in feet	3,200		2,700		3,200		1,418		1,650		1,200	
Drilling time, days	60		50		60		79		100		50	
	Total	Per ft.	Total	Per ft.	Total	Per ft.	Total	Per ft.	Total	Per ft.	Total	Per ft.
Derrick and rig	$ 4,500	$ 1.41	$ 4,800	$ 1.78	$ 5,000	$ 1.56	$ 4,750	$ 3.35	$ 5,000	$ 3.03	$ 4,326	$ 3.61
Engine and boilers	†	†	†	†	†	†	695	.49	660	.40	275	.23
Tanks, sumps and flow lines	3,000	.94	3,000	1.11	3,000	.94	*	*	*	*	*	*
Fuel and water	1,200	.38	1,150	.43	1,400	.44	908	.64	2,277	1.38	450	.37
Drilling	13,450	4.20	13,050	4.84	16,500	5.15	3,106	2.19	4,191	2.54	2,475	2.06
Casing	16,476	5.14	13,899	5.14	16,720	5.23	10,663	7.52	13,695	8.30	4,867	4.06
Cementing	....	......	....	......	....	......	780	.55	412	.25	375	.31
Shooting	920	.29	920	.34	920	.29						
Hauling	1,000	.31	1,150	.43	3,400	1.06	950	.67	743	.45	275	.23
Overhead and incidental expense	4,055	1.27	3,842	1.42	4,704	1.47	893	.63	1,419	.86	1,064	.89
Totals	$44,601	$13.94	$41,811	$15.49	$51,644	$16.14	$22,745	$16.04	$28,397	$17.21	$14,107	$11.76

Well No. 1: 82- by 22-ft. derrick; 6-in. rig irons; gas fuel; 350 ft. of 15½-in., 70-lb. casing; 800 ft. of 12½-in., 50-lb. casing; 1,400 ft. of 10-in., 40-lb. casing; 2,000 ft. of 8¼-in., 32-lb. casing; and 3,200 ft. of 6⅝-in., 24-lb. casing; 200 ft. of hard black lime requiring under-reaming; 200-qt. shot of nitroglycerin. Contract drilling at $3 per foot; black lime, $10 per foot.

Well No. 2: 82- by 22-ft. derrick; 6-in. rig irons; gas fuel; 800 ft. of 12½-in., 50-lb. casing; 1,400 ft. of 10-in., 40-lb. casing; 2,000 ft. of 8¼-in., 32-lb. casing; 2,700 ft. of 6⅝-in., 24-lb. casing; 150 ft. hard lime; 200-qt. shot of nitroglycerin. Contract drilling at $4 per foot; black lime, $10 per foot.

Well No. 3: 82- by 22-ft. derrick; 6-in. rig irons; gas fuel; 350 ft. of 15½-in., 70-lb. casing; 800 ft. of 12½-in., 50-lb. casing; 1,400 ft. of 10-in., 40-lb. casing; 2,200 ft. of 8¼-in., 32-lb. casing; and 3,100 ft. of 6⅝-in., 24-lb. casing. Contract drilling at $4.50 per foot.

Well No. 4: 82- by 22-ft. derrick; oil fuel; 530 ft. of 13½-in. stove pipe; 950 ft. of 10-in., 40-lb. casing; 1,250 ft. of 8¼-in., 28-lb. casing; 1,418 ft. of 6¼-in., 20-lb. casing. Long haul of materials. Soft shales and sandstones. Drilling cost is chiefly labor.

Well No. 5: 82- by 22-ft. derrick; oil fuel; 500 ft. of 12½-in., 40-lb. casing; 1,000 ft. of 10-in., 40-lb. casing; 1,575 ft. of 8¼-in., 28-lb. casing; and 1,650 ft. of 6¼-in., 20-lb. casing. Long haul of materials. Soft shales and sandstones. Drilling cost is chiefly labor.

Well No. 6: 74- by 20-ft. derrick; gas fuel; 806 ft. of 10-in. casing; 1,176 ft. of 8¼-in. casing. Steam furnished from boiler plant already in operation. Short haul of materials. Soft shales and sandstones. Drilling cost is chiefly labor.

Costs given for Wells 1, 2 and 3 are estimates, after J. R. Suman; those given for Wells 4, 5 and 6 are actual costs.

* Not included.

† Included with rig and derrick.

foot in some instances. Table XVIII indicates typical cable-drilling costs in several Western American oil fields.

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CHAPTER VI

ROTARY DRILLING: POWER DEVELOPMENT AND TRANSMISSION

The general features of the hydraulic rotary system of drilling were outlined in Chap. IV. We may conveniently classify the equipment used in this method of drilling under five headings, in accordance with their functional relationships: (1) the derrick and other supporting structures; (2) the power plant and power-transmission mechanisms; (3) the hoisting gear; (4) the rotating elements; (5) the circulating system. In Chap. IV, details of construction and design of derricks used in drilling operations were discussed. The present chapter will be devoted to a discussion of power development and application, primarily from the standpoint of one interested in the rotary system of drilling; however, much that is said here will apply equally well to other systems of drilling. Additional details on the specialized features of power plants appropriate for cable drilling have been presented in Chap. V.

POWER REQUIREMENTS FOR ROTARY DRILLING

The power consumed in operating a rotary drilling rig is used primarily in three different phases of the work: (1) rotating the drill column; (2) operating the circulating pumps; and (3) drawing out the drill column. The first two of these functions draw upon the source of power simultaneously. When hoisting operations are in progress, the other functions are nonoperative. In addition to these primary power-consuming operations, smaller amounts of power are needed for other purposes about the rig, as in operating fuel- and boiler-water pumps, vibrating screens, mud-mixing appliances, cement pumps, and electric lighting, but these requirements are of only minor importance in the over-all power consumption. In addition to power usefully employed, there is often a considerable stand-by loss, and transmission losses are in many cases an important percentage of the total power consumption.

A light portable unitized rotary drilling machine, designed for drilling to depths of less than 3,500 ft., may be powered with a single internal-combustion engine delivering a maximum of about 275 hp. On the other hand, heavy-duty rigs capable of drilling to depths in excess of 10,000 ft. may be equipped with prime movers aggregating from 1,000 to 3,000 hp. A large, heavy-duty steam-driven rig will require five 125-hp. boilers

delivering 350 lb. of steam. In one of the largest rotary rigs yet used, designed for drilling to depths of from 10,000 to 20,000 ft., five boilers were employed, each rated at 130 hp. and delivering 500 lb. of steam. This plant was capable of delivering 3,000 boiler hp. for a limited time. The largest twin-cylinder steam engines used on heavy-duty rigs, 15 by 14 in. in size, are capable of delivering 1,950 hp. with 500 lb. of steam at 250 r.p.m. A heavy-duty direct-connected steam-driven slush pump may require as much as 700 hp. when operating at 60 strokes per minute and delivering fluid under 1,000 lb. pressure. When two such pumps are operated in series to attain pressures sometimes as great as 3,000 lb. per sq. in., the power requirement will be correspondingly greater. Rotating the drill column may require as little as 20 hp. at low speeds in shallow holes, or as much as 120 hp. when rotating at high speeds in deep holes. A heavy-duty "mechanical" rig capable of drilling to depths in excess of 10,000 ft. will usually be powered with three 350-hp. diesel engines.

SOURCES OF POWER USED IN ROTARY DRILLING

Steam equipment has been generally preferred for rotary drilling and steam-driven rigs are still most used. Most drillers believe that no other prime mover possesses the flexibility in speed and torque that is inherent in the steam engine. However, recent improvements in internal-combustion engines and transmission mechanisms have produced a thoroughly satisfactory power plant for drilling purposes and the economies of this type of power in comparison with steam have led many operators to adopt it, especially where fuel and water costs are high. Electric motors of modern design, with appropriate resistor controls and operating through suitable power-transmission mechanisms, provide a sufficiently flexible source of power with characteristics well adapted for rotary drilling purposes. Where electric power is conveniently available from a utility company and at a favorable price, it may be used with entire satisfaction. Where utility electric power is not available, diesel engine-powered electric drive using d-c motors combines the convenience of electrical transmission and application with the economy of the diesel engine as a prime mover, and provides a flexibility of control that rivals steam power. Each of these three fundamental types of power—steam engine, internal-combustion engine and electric motor—has been successfully adapted to rotary drilling in many field installations and may satisfactorily meet all power requirements in rotary drilling service. The choice of one or the other is generally resolved into a question of economy, convenience in transportation or individual preference. The driller's previous training and experience and familiarity with one type of equipment or another will often deter-

mine his preference. Probably this is one reason why steam equipment continues to be the popular choice, though it is often used where other types of power plant would be more economical.

Steam Power Plant for Rotary Drilling

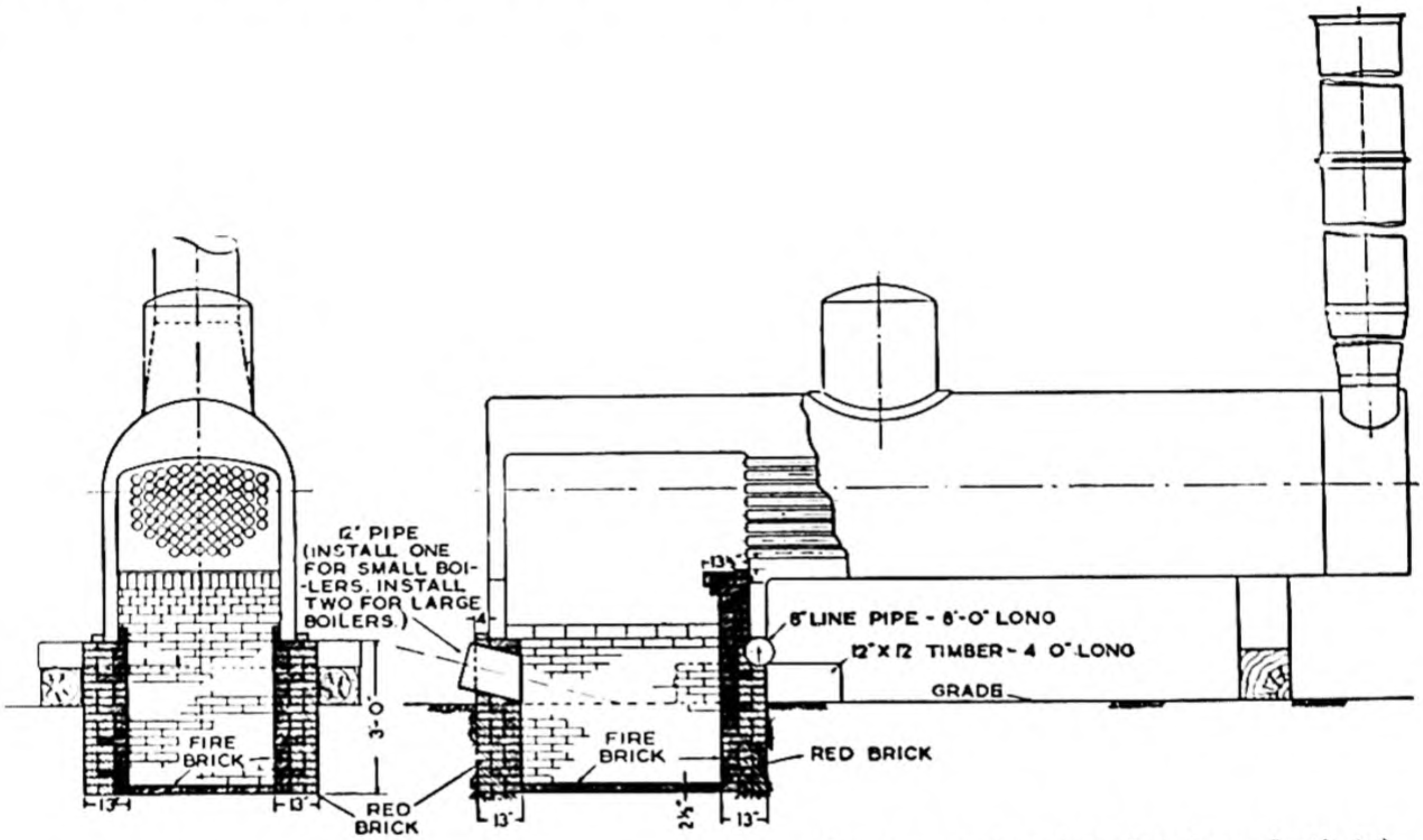
When steam equipment is used, consideration must be given to problems of fuel and water supply, transport and installation of boilers, provision of water-, fuel- and steam-transmission lines and many other details. As indicated in an earlier section, a boiler plant consisting of as many as five 125-hp. 350-lb. steam pressure units must be provided for a deep drilling operation. Such a plant will require on the average, about 1,250 bbl. of feed water per day; if fired with 1000 B.t.u. natural gas, it will consume 750,000 cu. ft. of gas per day. Under peak-load conditions, the water and fuel demand may be from two to three times the rates specified. A large percentage of the time of one member of the drilling crew will be required in operation of the boiler plant. In addition, when one considers the high initial cost, short life and high maintenance cost of steam equipment, it becomes apparent that this type of power plant is expensive.[10,11]

All possible means of increasing the operating efficiency of the boiler plant and of improving the economy in use of power in rig operation will be worthy of serious attention. Efficient combustion of fuel, frequent scaling of boiler tubes, provision of automatic fuel supply and water-level regulators, preheating of boiler water, superheating of steam, proper design and insulation of steam-transmission lines to minimize pressure and heat losses, and operation at rates that will permit of realization of maximum boiler efficiency will result in important operating economies. Power for the entire drilling operation must come out of the boilers and so much depends in operation of the rig—especially at critical times—on having available a sufficient supply of steam, that this part of the field equipment should be selected with particular care. Ample capacity to meet peak-load demands, dependability in day-to-day operation and convenience in assembling, dismantling and transportation are important considerations in the selection of boiler equipment.

The location of the boiler plant with respect to the site selected for the well must receive careful consideration. It should, if possible, be at a lower elevation, on the windward side with reference to prevailing wind direction, and at least 75 ft. and preferably 150 ft. distant from the well. In determining this distance, the operator must strike a balance between the fire and explosion hazards of close proximity and the transmission losses and inconvenience of having the boiler plant too far away. The engineer in charge of the boiler-plant installation should check every detail to be assured that it complies with the safety code of the state in

which the well is situated. The American Society of Mechanical Engineers and the American Petroleum Institute have recommended codes that are a dependable guide in assuring proper engineering design and installation.[2,14]

Boilers used in steam generation may be either the fire-tube, water-tube, locomotive or Scotch marine type. Contract drillers, who today drill most of the oil and gas wells in the United States, generally prefer the locomotive type, in which a water-jacketed metal firebox is riveted directly to the boiler shell (see Fig. 70). This type of boiler is especially useful for temporary service, since it requires less in the way of



(*Courtesy of American Petroleum Institute.*)

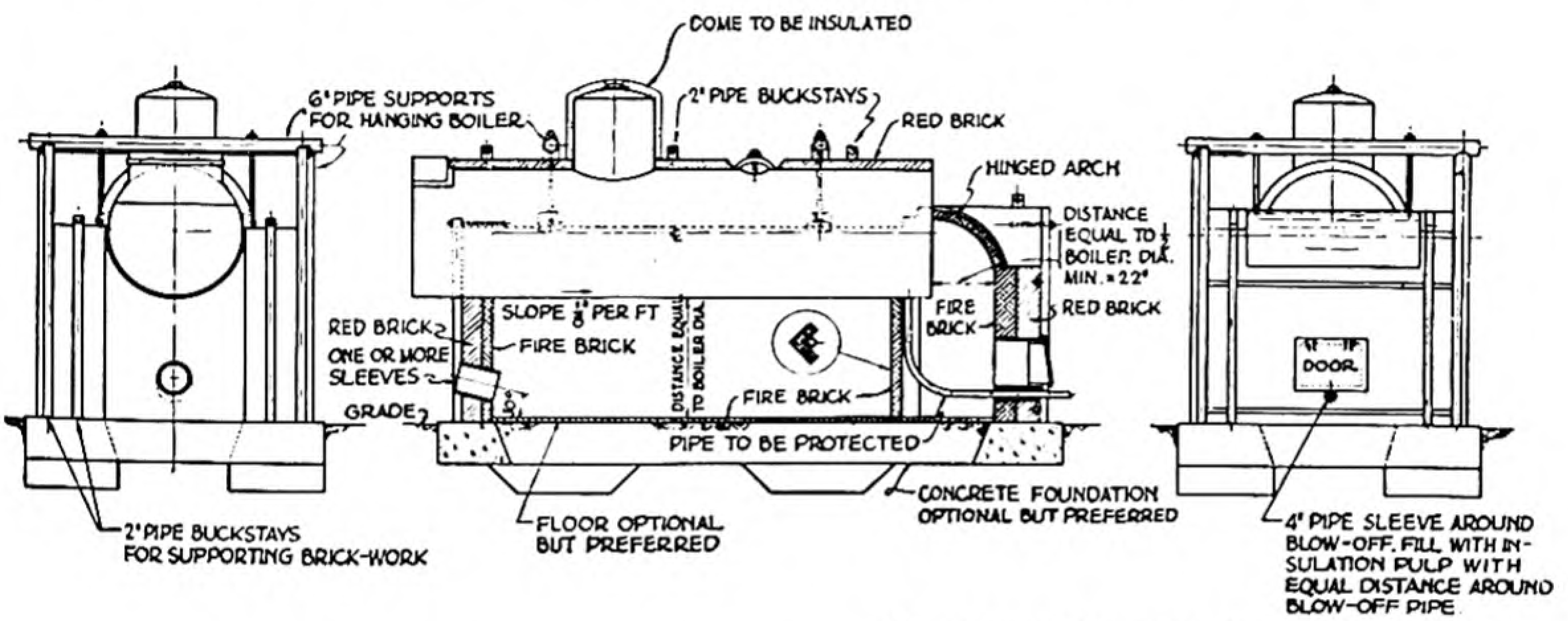
FIG. 70.—Locomotive type of steam boiler commonly used in drilling operations.

masonry supports than other types and it can be quickly moved and set up in a new location. In this connection, it should be remembered that, under modern conditions, a well can be drilled in from 10 days to 3 months and the rig is not long in any one location. Another type very commonly used in oil-field drilling operations is the horizontal return fire-tube boiler, generally mounted on brick supports above a brick firebox (see Fig. 71). This type is less costly and is easily transportable, but requires more masonry in its "setting" and more time in "rigging up" than are necessary with the locomotive type.

During earlier years, when wells were seldom more than 5,000 ft. deep, rotary rigs were powered with steam equipment designed for 150 to 200 lb. working pressure. Three 65- or 85-hp. boilers were generally sufficient to meet all power requirements with considerable reserve steam-generating capacity. With deeper drilling, the greater drill-pipe hoisting loads and the greater drilling fluid volume and pressure demanded increased power. This could be attained with 150 to 200 lb. of steam only by making steam cylinders so large as to become unduly heavy and unwieldy. To avoid this, manufacturers of modern, heavy-duty rotary drilling rigs have turned to higher steam pressures. Steam equipment designed for 350 lb. of pressure is now

commonly used in deep-well rotary drilling, and some operators have been interested in development of equipment designed for pressures as high as 500 lb. per sq. in. There are, of course, some disadvantages in use of high-pressure equipment, notably leakage losses and greater cost and weight of boilers, engines, transmission mains and fittings.

The number of boilers will normally range from three to five, depending upon power requirements. It is considered good practice to provide one more boiler than actually necessary for routine rig operation. Though normally kept under fire and ready for emergency or peak-load requirements, the extra boiler is really a stand-by unit. With a reserve boiler, one or another unit of the battery can be cut out of service from time to time as scaling or other maintenance work becomes necessary, still leaving sufficient steam-generating capacity in use for normal drilling.



(*Courtesy of American Petroleum Institute.*)

FIG. 71.—Horizontal-return fire-tube boiler of oil-country type.

Selection of boiler sizes and weights is conditioned by difficulty in transportation. For low-pressure steam plants, 65-hp. boilers designed for 175 lb. working pressure and 85-hp. boilers designed for 200 lb. steam pressure have been widely used with light rotary rigs in drilling to shallow and moderate depths. Boilers of this size can be conveniently transported over the roads usually provided and with the facilities usually available. Larger sizes, frequently used where roads are adequate and highway laws permit, are the 100-hp. boiler designed for a working steam pressure of 200 lb. per sq. in. and the 125-hp. boiler designed for working pressures up to 300 lb. per sq. in. Boiler pressures are ordinarily about 50 lb. greater than working pressures. Table XIX gives sizes of locomotive-type oil-field boilers that have been adopted as standard by the A.P.I. together with their dimensions and weights.

Boiler Water Supply and Water-control Devices.—Water supply for a boiler plant serving a rotary rig may vary from 1,000 to 2,000 bbl. per 24 hr., depending upon the capacity of the boilers and steam requirements. For average conditions, 1 cu. ft. of water per hour will be needed for each boiler horsepower, allowing 10 sq. ft. of heating surface per boiler horsepower. All surface waters contain more or less suspended solids, organic matter, acids and dissolved salts that tend to accumulate in the boilers as sludge or scale and perhaps cause "foaming" or "priming." Water supply obtainable in most oil-producing regions is particularly likely to be laden with such impurities, and provision must usually be made for treating the boiler water before use, by suitable means. The primary purpose of such treatment is to coagulate the suspended solids and reduce the incrustating or scale-forming tendencies of the dissolved substances.

The boiler feed water must, of course, be forced into the boilers under pump pressures somewhat in excess of the steam pressure carried, and for this purpose two feed-water pumps are provided, often 10 by 4½ by 10 in. in size. These pumps are steam-driven and are usually combined with a small heat exchanger for preheating the boiler feed water. Exhaust steam from various steam-consuming units of the rig is led to this preheater so that it also serves as an exhaust steam condenser. Water injection temperatures of 175 to 200°F. may thus be maintained, materially reducing the heating duty of the boilers and serving also to remove some of the foreign matter from the water before it enters the boiler. Preheating in this way may save as much as 22 per cent of the fuel consumption under some conditions.

TABLE XIX.—SIZES, DIMENSIONS AND WEIGHTS OF LOCOMOTIVE-TYPE BOILERS*

A.P.I. horsepower ratings	86 hp.		104 hp.		125 hp.	
Working pressure, lb. per sq. in.	250	300	250	300	250	300
Heating surface, A.S.M.E., sq. ft.	860	860	1,040	1,040	1,252	1,252
Length of boiler	18′8½″	18′8½″	22′6″	22′6″	24′6″	24′6″
Height of boiler	9′10¾″	9′10¾″	10′10″	10′10″	10′10″	10′10″
Width of boiler	5′2″	5′2″	5′2″	5′2″	5′2″	5′2″
Weight of boiler, complete, lb.	21,300	23,325	27,000	29,000	30,000	33,000

* As manufactured by the Lucey Boiler & Mfg. Corp.

Modern field boiler installations are also equipped with automatic pump governors that regulate the speed of the pumps to maintain a proper water level in the boilers. For visual inspection, boilers are also equipped with sight gauges that show the water level inside the boiler, and for added security a low-water-level alarm may be installed. Facilities must of course also be provided for blowing down the boilers to evacuate residual water and scale. This may have to be done at hourly intervals where the water supply is impure. Provision for continuous blowdown by evacuating boiler water continuously through a system of small orifices is adopted by some operators. Every boiler must, of course, be equipped with a suitable safety valve, set to discharge from the boiler when a certain pressure is exceeded. This maximum pressure will be one for which the design and condition of the boiler provide an amply safety factor. The A.S.M.E. code and state industrial safety codes provide a limiting pressure for every boiler, and frequent inspection of boiler equipment is required by law to give assurance of safety under all normal use.

Superheating.—Increased efficiency in steam-power development can be obtained by passing the steam produced by a field boiler plant through a superheater. A steam superheater is an apparatus designed to increase the temperature of steam without increasing its pressure. It consists of a system of tubular elements through which the steam flows while being heated by hot gases circulating about the tubes. Steam direct from the boiler plant is thus heated with fuel burned in the firebox of the superheater, usually to a temperature of from 50 to 100°F. higher than that of the entering steam. Saturated steam, ready to condense on slight reduction of temperature, is thus converted into a condition that causes it to behave more like a true vapor, increasing its volume so that it moves through the transmission mains with greater velocity, with less radiation loss and with a minimum tendency to condense.

One hundred degrees of superheat will increase the steam volume about 18 per cent; when the smaller condensation losses are taken into account, the power may be increased by 20 per cent or more. Though they are of unquestioned advantage in stationary steam plants, efficiently designed and installed for long service, some authorities question the economy of superheaters under the "rough-shod" conditions existing in most oil-field boiler plants temporarily installed for drilling purposes. A field boiler plant must generally be designed to provide a generous stand-by capacity that is used for only a small percentage of the total time, and increasing the normal output of the plant by 20 per cent may not be of sufficient importance to justify the cost of the superheater, particularly if fuel and water are cheap. A superheater costs about as much as an additional boiler and burns about 60 per cent as much fuel as a 125-hp. boiler. The additional volume of steam that the superheater affords might therefore cost nearly as much as if developed by the extra boiler capacity with which the plant must be equipped in any case. It is also claimed that the types of prime movers used at drilling rigs, particularly the steam ends of slush pumps, are not designed to take full advantage of the added efficiency that superheated steam affords. As much as 70 per cent of the over-all output of the boiler plant is consumed in operation of the slush pumps.

Boiler Ratings, Capacities and Efficiencies.—American Petroleum Institute specifications for oil-field boilers provide that they shall be rated on the basis of 1 hp. for each 10 sq. ft. of metal heating surface actually in contact with hot gases on one side and water on the other. This surface area is supposedly capable of evaporating 34.5 lb. of water per hour at 212°F. This is an entirely arbitrary rating basis which assumes that heat absorption is at the rate of 33,479 B.t.u. per hr. for each 10 sq. ft. of heating surface. Actually the quantity of heat absorbed is highly variable, depending upon the quantity of fuel that can be burned in the firebox, the combustion efficiency, stack losses, and the rate of heat transfer, which in turn varies with the thickness of metal, radiation and conduction losses and the amount of scale or sediment on the metal surfaces. With efficient provisions for burning fuel, it is possible to develop power output from oil-field boilers equivalent to three or four times their normal ratings. Thus a boiler rated at 125 hp. may for a time deliver steam power at the rate of as much as 500 hp. Boilers might be more scientifically rated on the basis of the number of pounds of steam per hour that they are capable of delivering, rather than on the horsepower basis.

Output of a boiler in pounds of steam per hour is conveniently determined with the aid of the following formula:

$$W = \frac{QE}{(H - h)}$$

Here W is the number of pounds of steam generated per hour; Q is the heat produced by the burning fuel, in B.t.u. per hour; E is the over-all boiler-plant efficiency; H is the heat content of steam generated at the observed pressure and temperature above 32°F., in B.t.u. per pound; h is the heat content of the boiler feed water above that contained at 32°F., in B.t.u. per pound.

Because of primitive heat-conservation measures, cheap natural-gas fuel and consequent waste in its use, and also because of the highly variable load factor, oil-field boiler plants usually operate with lower efficiency than is usual in most industrial boiler plants. Careful engineering studies of boiler installations at drilling wells, when operating under average conditions, have indicated that over-all efficiencies ordinarily range between 50 and 60 per cent but may be lower when little attention is given by the field crew to economic methods of operation. Efficiencies as high as 70 per cent may be attained with well-insulated boiler plants operating

with carefully controlled fuel combustion and maximum efficiency in heat transfer. Thorough insulation increases over-all efficiency by from 4 to 10 per cent, depending upon climatic conditions and effectiveness of the insulating material.

Maximum boiler efficiency is attained at a certain optimum rate of power development, which is generally somewhat above the rated horsepower of the boiler. Thus, tests of a 100-hp. boiler (as rated under the A.P.I. code) indicated maximum efficiency of 60 per cent when operating with an output of 190 boiler hp.; and a 65-hp. boiler developed a maximum efficiency of 69 per cent when operating with a 90-hp. output.

Over-all efficiency of a boiler may be computed with the aid of the following formula:

$$E = \frac{W(H - h)}{Q}$$

Here E is the over-all efficiency of the boiler plant; W is the number of pounds of feed water evaporated per pound of fuel; H is the total B.t.u. per pound of steam at observed pressure and temperature above 32°F.; h is the heat content of feed water in B.t.u. per pound in excess of that present at 32°F.; Q is the heating value of the fuel in B.t.u. per pound.

The efficiency of combustion in a field boiler is conveniently indicated by analysis of the flue gases and recording their temperature. The stack temperature in an oil-field type of boiler, under normal operating conditions, is usually about 700°F. Lower stack temperatures indicate that more air is being used than is needed for efficient combustion; higher stack temperatures indicate that more fuel is being burned than can efficiently be handled and utilized with the existing boiler arrangements. A sample of the flue gas can quickly be analyzed for its CO_2 content with gas-analysis equipment designed for field use. Values range from 7.5 to 12 per cent. Reference to engineering tables enables the operator to determine quickly the heat loss for any observed conditions of stack temperature and CO_2 content of the flue gases. Heat losses range up to as much as 30 per cent under adverse conditions.

Steam Transmission.—The economy and effectiveness of steam power are influenced to an important degree by the design and character of the steam piping. Unless the pipes are protected against heat radiation, power loss will result through condensation of steam and consequent loss of pressure. Leakage of steam at pipe joints and fittings may also be responsible for important losses. In long steam lines, the pipes must be of adequate cross section to accommodate the volume of steam to be transmitted without excessive frictional resistance. Where branched mains are necessary, the sizes of pipe used must be proportioned to the volume of steam that each branch is to carry.

For short steam lines, say, from 50 to 100 ft. long, the cross-sectional area of the steam main should be about one-fifteenth of the area of the piston to be driven. This ensures nearly full boiler pressure at the engine. For longer lines, as used in distributing steam from a central power plant to a number of drilling wells, the pipe sizes must be increased; otherwise there will be serious loss of pressure at distant points. The size of the pipe must also be proportioned to the maximum demand that is likely to arise, and will naturally be in excess of average demand. Radiation losses and frictional losses are opposing factors in the design of steam lines. As the size of pipe increases, radiation losses increase; as the size decreases, friction losses increase. In either case, loss in pressure results. In modern practice, steam velocities ranging from 6,000 to 15,000 ft. per min. through the transmission mains are not uncommon.

The flow of steam through pipes is governed by the same hydraulic laws that apply to all fluids. The Fanning formula, widely used in hydraulic computations, can be applied to determine the unknown factors in steam flow through a given pipe-

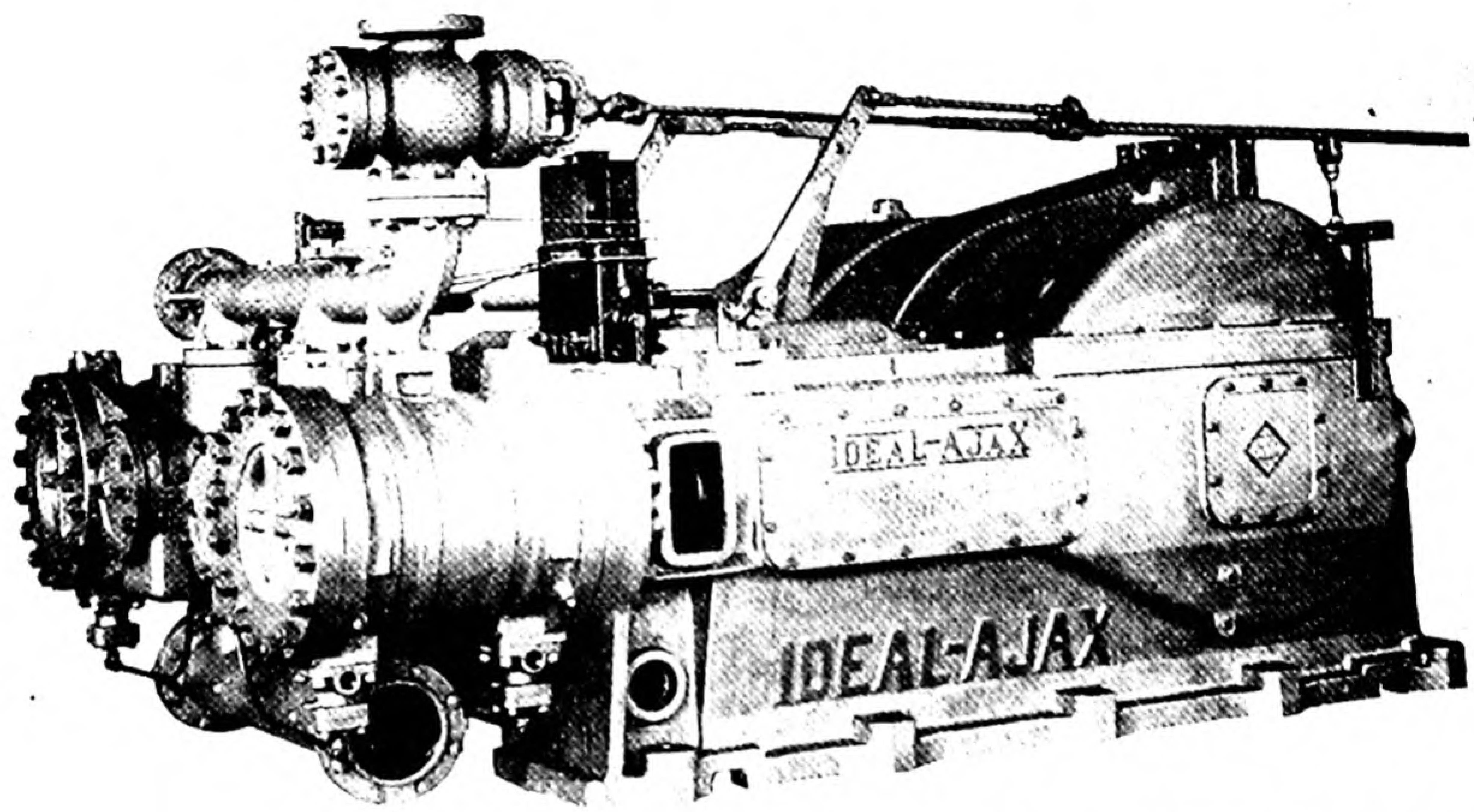
line system if the necessary variables are known or can be evaluated. In connection with such computations, the density of steam at different temperatures and its kinematic viscosity must be determined.

Radiation losses in steam piping, with consequent condensation, can of course never be avoided entirely, but can be greatly reduced by the application of suitable pipe coverings. Bare pipe will radiate approximately 3 B.t.u. per hr. per sq. ft. of exposed surface for each Fahrenheit degree difference in temperature between the steam and the external air. This figure may be reduced to from 0.3 to 0.4 B.t.u. for the same conditions, by application of a 1½-in. insulating covering. Mixtures of asbestos, hair and carbonate of magnesia are the most efficient coverings. For best results, all exposed main steam lines, flanges, valve bodies and fittings should be covered with from 1½ to 2 in. of such material. All metal surfaces should be painted before the covering is applied. Canvas held in place by iron or brass bands is ordinarily placed over the magnesia covering to prevent it from disintegrating. A moderate investment in insulating material will soon be repaid by steam saved. Steam lines from a boiler plant in the field to the well are preferably buried in the ground. In this case, the pipe may be surrounded in the trench with oil sand which has excellent heat-insulating qualities. When pipes are placed aboveground, they may be surrounded by a rectangular wooden trough filled with oil sand.

Steam-distributing pipes should be carefully graded, if possible, to a uniform slope, so that condensed water will be gathered at definite points and removed by suitable traps or drains. The slope should be in the direction of steam flow. Whenever a rise is necessary, a drain or trap should be installed. All main headers and branches should end in a "drop leg," and low points may be connected to a drainage pump which returns the condensed water to the boiler plant. Branched mains should be taken from the top of a main header rather than from the bottom. Each engine should have its own trap or separator, placed as near the throttle as possible and all separators should be connected with the drainage system.

Steam Engines for Rotary Drilling.—A steam-driven rotary drilling rig is conventionally equipped with one twin-cylinder engine to drive the draw works and rotary table, and two direct-connected duplex steam-driven slush pumps. There are thus six engine cylinders to be supplied with steam. Other arrangements are possible and are in common use. For example, the engine provided to drive the draw works and table may be a three-cylinder engine. Or a separate engine may be used to drive the rotary table, apart from that which provides power for the draw works. A single engine may be belted to the pumps and so arranged that it may drive either pump separately or both at once. On lightweight, portable rigs, the engine that operates the draw works and rotary table may also be belted to the pumps; or, with a truck-mounted rig, the truck engine may drive the pumps. In addition to these primary units, a heavy-duty rig may have a stand-by draw works, powered with its own separate engine; and small steam turbines are often used to operate vibrating screens and an electric generator to provide current for electric lighting. The boiler-plant feed-water and fuel pumps (if oil is used), and perhaps also the fuel burners in the boiler-plant fireboxes, will draw upon the steam supply.

The engine provided to drive the draw works—and generally also, the rotary table—is the principal prime mover in the rotary rig. As indicated in the foregoing paragraph, it is customarily a horizontal, duplex, twin-cylinder type of engine, often with cylinders 12 in. in diameter and with a 12-in. piston stroke, designed for 350 lb. steam pressure (see Fig. 72). For lighter service, 10- by 10-in. or 12- by 12-in. engines of the same type are used, designed for a maximum of 250 lb. steam pressure; and for heavy-duty rigs used in drilling to depths in excess of 10,000 ft., 14- by 14-in., 15-by 14-in., and 16- by 14-in. engines are available. Some of the latter are designed for steam pressures of 400 or 500 lb. per sq. in. Modern engines of this type are designed for rugged service. Their structural features include one-piece semisteel frames; alloy-steel crossheads, and crankshafts; counterbalanced disks; roller bearings; moving



(Courtesy of National Supply Co.)

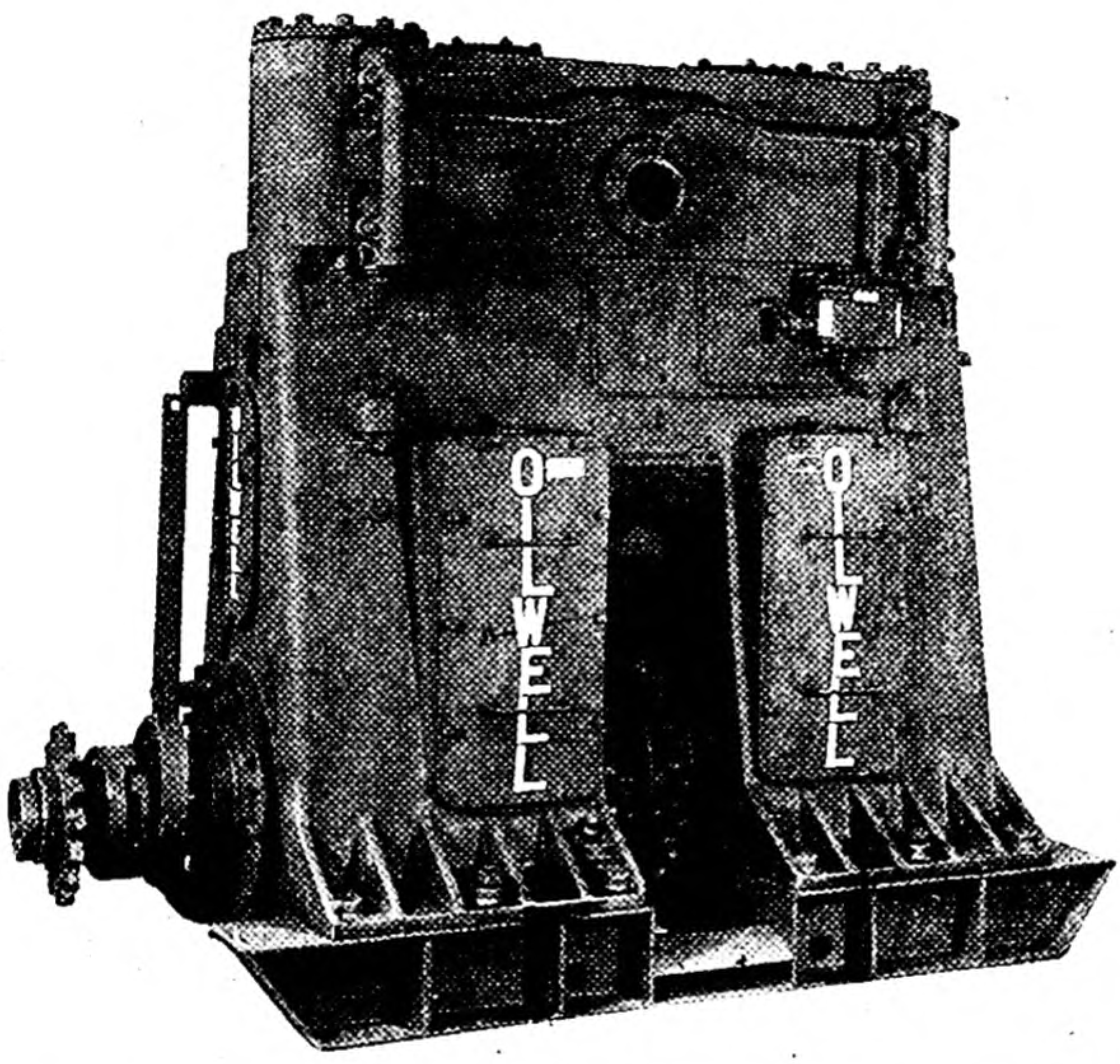
FIG. 72.—Horizontal twin-cylinder steam engine, a type widely used for rotary drilling purposes.

parts entirely enclosed; either piston-type steam valves or balanced slide valves; continuous splash lubrication to all moving parts and alemite fittings for grease lubrication of bearings. Steam cylinders and valves are preferably lubricated by a forced-feed mechanical lubricator. The crankshaft is equipped with a cast-steel sprocket for chain transmission of power to the draw works or intermediate mechanism. The cranks are set 90 deg. apart, assuring easy starting, quick acceleration from rest and rapid reversals without excessive shocks when the engine is in motion. Weights range from 5,750 lb. for lightweight 10- by 10-in. engines, to 30,400 lb. for the heavy-duty 16- by 14-in. engine. The commonly used 12- by 12-in. engine, designed for 400 lb. working pressure, weighs 16,340 lb.

The power developed by such engines depends upon the steam pressure and the speed at which they may be operated. They are normally rated for a speed of 250 r.p.m. but the better constructed engines can safely be driven for short periods of time at speeds as high as 500 r.p.m. With a 12- by 12-in. twin-cylinder engine, operating at 300 r.p.m. and 150 lb. steam pressure, 275 hp. may be developed. A 14- by 14-in. heavy-duty engine, operating with 350 lb. steam at a speed of 250 r.p.m., develops

1,070 hp. At 380 r.p.m., its maximum safe recommended speed, the power developed is 1,330 hp. Under the best conditions possible, such engines will consume from 30 to 40 lb. of steam per horsepower-hour. With only one-quarter full load, this figure may be nearly doubled; and with generally poor mechanical repair, characteristic of many oil-field installations, the steam consumption may range up to 100 lb. per hp.-hr.

Although most steam engines used in driving rotary drilling rigs are of the conventional twin-cylinder horizontal type, during recent years there have been many installations of vertical twin-cylinder engines, which appear to have certain advantages. A typical engine of this type is pictured in Fig. 73. In comparison with the



(*Courtesy of Oil Well Supply Co.*)

FIG. 73.—Vertical twin-cylinder steam engine designed for rotary drilling.

horizontal type, vertical engines are more compact and occupy less floor space. This type of construction permits of more effective counterbalancing; piston thrust is directly downward against the foundations, resulting in less vibration in operation; and because of these features, higher operational speeds are possible. One manufacturer builds these engines in three sizes, affording a wide range of application in oil-field service. The largest, 12 by 12 in. in size, designed for 350 lb. manifold steam pressure, with speeds up to a maximum of 500 r.p.m. and weighing 16,000 lb., is comparable in power output with the equivalent size of horizontal engine. The second size, 10 by 9 in. and weighing 11,180 lb., develops 660 hp. at 400 r.p.m. with 300 lb. manifold steam pressure. Designed for a maximum of 350 lb. steam pressure, it may safely be operated for short periods at speeds as high as 700 r.p.m. The smallest size, 7¾ by 7 in., develops 310 hp. at 400 r.p.m. with 300 lb. steam, has a speed range of 40 to 700 r.p.m. and weighs only 6,590 lb. These engines are designed for a wide range of hand-controlled cutoffs and, by proper adjustment, important economies in

steam consumption are realized. The smaller sizes, mounted on skids, provide an easily portable power unit, flexible and adaptable to drilling equipment in a variety of ways. For example, such an engine may be geared directly to a rotary table or applied through a V-belt drive to a power-driven slush pump. Two of them may be arranged in tandem to drive a heavy-duty draw works through a suitable intermediate transmission mechanism. Another manufacturer has pioneered in the development of three-cylinder vertical drilling engines. Adaptable to either high, low or intermediate steam pressure by interchangeable cylinder liners, the Hydril 10- by 10-in. three-cylinder engine, with 150 lb. steam pressure, develops 320 hp. at 320 r.p.m. (see Fig. 128).

Internal-combustion Engines for Rotary Drilling.—Although not used to the extent that steam engines are employed in rotary drilling, there have been many applications of internal-combustion engines in this service during recent years and the popularity of this type of prime mover has been rapidly increasing. Internal-combustion engines as a class include all engines operating on gaseous or liquid fuels in which the fuel is burned or exploded within the engine cylinders or within recesses communicating directly therewith. We may classify such engines in accordance with the fuel employed, as gas engines, butane engines or oil engines. Also, they may be classified further as two-cycle or four-cycle engines, horizontal or vertical engines, single- or multicylinder engines, explosive-type or diesel-type engines. All these types of internal-combustion engines have found application in rotary drilling service, but naturally some are preferable to others. Of the various types of engines comprising this group, the vertical multicylinder gas engines using natural gas or butane as fuel and the vertical multicylinder diesel or semidiesel engine operating on various types of fuel oil or crude oil have been used most widely for rotary drilling.

Internal-combustion engines have certain well-defined advantages and disadvantages in comparison with steam equipment in providing power for rotary drilling rigs. They are less flexible in speed and torque than steam engines and are higher in first cost and maintenance cost, and some types are larger and heavier than steam engines, though when the size, weight and cost of the necessary boiler equipment are taken into account, the advantage in these respects lies with the internal-combustion engine. Lack of flexibility of the internal-combustion engine, formerly an important bar to its use in drilling service, has of late been largely offset by new systems of power transmission which have greatly improved its performance. The principal advantage of the internal-combustion type of engine, particularly the diesel engine, is found in its high fuel and water economy, making it particularly desirable in situations where fuel is scarce or costly, or where water is expensive or not sufficiently pure for steam-boiler purposes. In addition to this advantage, the smaller sizes of internal-combustion engines are compact, easily portable,

and may quickly be installed and moved from one location to another. As soon as it is placed on suitable foundations and fuel and water connections are provided, it is ready to run. Equipped with its own steel housing in the form of a removable hood, it requires no other protection from the weather.

Gas, gasoline and butane engines may be considered as a group inasmuch as they are all internal-combustion engines in which a carbureted mixture of gaseous or vaporized fuel and air is exploded in the power cylinders. Both two-cycle and four-cycle engines of this group are employed, and they are available either in horizontal, single-cylinder types or vertical, multicylinder types. For rotary drilling purposes, the vertical, multicylinder engines seem best adapted.

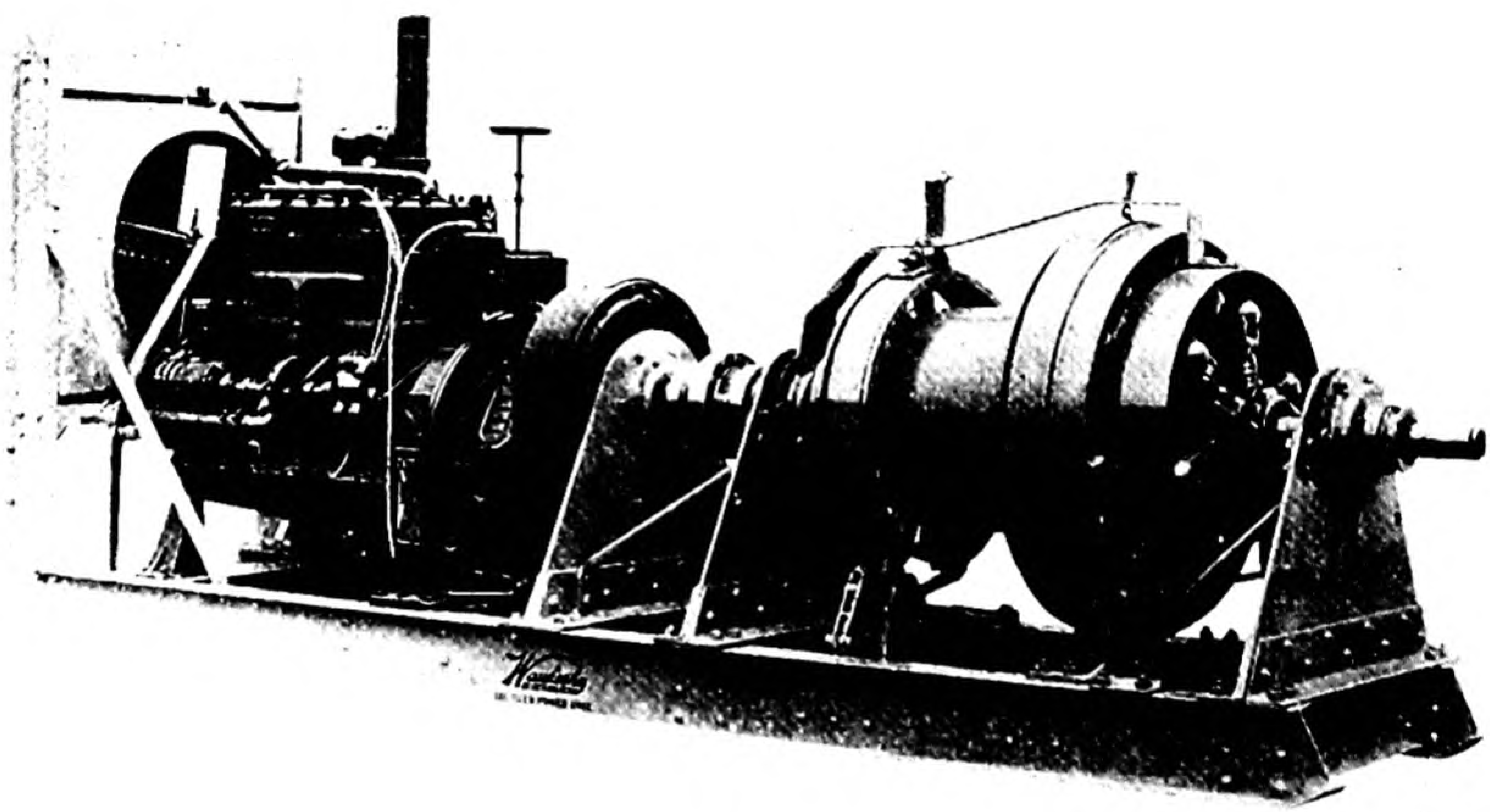
If an engine of the explosive type is designed to operate with a sufficiently high compression ratio (4.5: 1 or higher), it can readily be adapted to use either natural gas, gasoline or butane by making slight changes in the carbureting system. The choice of one fuel or another is generally resolved into a consideration of relative costs. Gasoline is ordinarily too expensive to use as a drilling engine fuel and would be employed only when other fuels are not available. In many oil-producing districts, a supply of natural gas sufficient for engine operation is readily available at low cost. If so, it will generally be found the most advantageous fuel. However, if gas is not plentiful or is expensive, or if the location of the well to be drilled is remote from a source of gas so that a long pipe line would be necessary—as in the drilling of a wildcat well—butane or gasoline may be preferable. Commercial butane is now available at low cost in many regions adjacent to producing oil fields. It is transported and stored as a liquid in high-pressure containers but, owing to its high vapor pressure, is readily vaporized and carbureted and exploded in the engine as a gas. When available at reasonable cost, it is an ideal fuel for operation of internal-combustion engines of suitable design, and is now widely used in operation of "spark-plug" rotary drilling rigs.

Commercial butane, a by-product in the extraction of gasoline from natural gas, usually contains from 5 to 20 per cent of propane. It is a liquid at 10°F. and atmospheric pressure, but at 100°F. it develops a vapor pressure of 70 lb. per sq. in. or more. It weighs 4.7 lb. per gal. Under full load, engines powered with butane fuel require 0.43 to 0.6 lb. of fuel per horsepower-hour. Butane is superior to gasoline as an internal-combustion engine fuel, in that it behaves in the engine as a true gas and there is no condensation on the walls of the engine manifold and cylinders and no dilution of the crankcase lubricant. Combustion is practically complete, with no tendency to form carbon deposits. It has an octane rating of approximately 100 and consequently gives superior performance in an engine designed for suitable compression ratio (preferably 7: 1 or 8: 1). No unusual hazards are presented in using butane as an engine fuel, except that pressure containers must be provided for storage, together with suitable valves and pressure regulators.

Gasoline averages about 20,200 B.t.u. per lb., or 133,200 B.t.u. per gal., and in engines of this type develops about 10 brake hp.-hr. per gal. Butane has an average heat content of 21,200 B.t.u. per lb. or 102,000 B.t.u. per gal., and also develops about 10 hp.-hr. per gal. Natural gas has an average heat content of 1,150 B.t.u. per cu. ft. and develops about 100 hp.-hr. per 1,000 cu. ft.

Drilling engines designed for explosive fuel are preferably of the vertical, multicylinder, automotive type. Although horizontal, single-cylinder engines are widely used for operating pumping mechanisms in producing wells and are occasionally used in cable drilling, they are not well adapted for rotary drilling purposes. Multicylinder

vertical drilling engines, designed to operate on natural gas, gasoline or butane, may have from 4 to 12 cylinders (generally 6 or 8), operate at speeds ranging from 600 to 1,800 (often 900 or 1,200) r.p.m. and deliver from 15 to 400 brake hp., depending upon speed, size of cylinders and length of stroke. Figure 74 pictures an engine of this kind. A typical engine of this type has six cylinders of 6-in. bore and a piston stroke of 7 in., or a piston displacement of 1,187 cu. in. per cycle. It has a continuous duty rating of 126.4 hp., but at the safe maximum speed of 1,100 r.p.m. will develop 158 hp. A heavy "mechanical" rig designed for drilling to depths as great as 7,500 ft. uses two $8\frac{1}{2}$- by $8\frac{1}{2}$-in. engines of 2,894 cu. in. displacement, each developing 335 hp. at 900 r.p.m. Still another mechanical rig, capable of drilling to depths



(*Courtesy of Waukesha Motor Co.*)

FIG. 74.—Vertical automotive type of gas engine with reversing clutch and reduction gear.

up to 10,000 ft., uses two 2-cycle 6-cylinder drilling engines, size $8\frac{3}{4}$-in. bore by $9\frac{1}{2}$-in. stroke, each developing 240 brake hp. at 600 r.p.m. Each of these engines weighs 18,500 lb.

Multicylinder gas engines of this type, appropriate for oil-field drilling service, are available from several different manufacturers, and design and structural features vary accordingly. Important considerations include the ignition system, the carburetion system, the cooling system, lubrication provisions, arrangements for starting the engine, accessibility for repairs, fuel economy, speed and torque characteristics, weight and convenience in transport. Ignition is by means of spark plugs, with the electrical impulse furnished either by a magneto or a storage battery. The latter is best adapted for the larger sizes of engines used in rotary drilling rigs and permits of use of an electric starter. Timing of the electrical discharge is important and varies with the engine speed, compression ratio, combustion-chamber design and plug location. The "multiple-electrode" type of spark plug is favored and a "cold" plug is preferred if natural gas is the fuel used. Efficient carburetion requires a supply of dry gas of uniform heat content and pressure and free from impurities. Water in the gas supply is often troublesome and, to remove it, a scrubber should be placed in the fuel line near the engine. A filter in the gas line between the scrubber

and the engine, to remove all entrained solid matter, is also helpful. To maintain uniform pressure on the gas supply, a pressure regulator or reducing valve is provided, usually designed to reduce the line pressure of about 20 lb. per sq. in. to 8 in. of water at the carburetor connection. An air filter is desirable in the air-supply piping to the carburetor. The air-gas ratio will vary in straight-line relationship with the thermal value of the gas, ranging usually from 9 to 1 to 11 to 1 for natural gas of normal range of heat value (*i.e.*, 1000 to 1240 B.t.u. per cu. ft.). Crankcase lubricants are usually automobile oils of suitable viscosity, and attention must be given to maintenance of proper crankcase temperatures and crankcase ventilation to avoid formation of emulsified sludge by condensation of water vapor. The cooling system generally incorporates an automotive-type radiator and fan of large size and a water pump. Assuming an operating temperature of 170°F., from ½ to 1 gal. of water per minute is pumped through the cooling system for each horsepower developed. The efficiency of an internal-combustion engine increases with the operating temperature because less fuel can be burned per cycle. The practical limit of temperature at which the engine can operate will be the boiling temperature of the water in the cooling system. High engine temperatures occasion excessive water and lubricating oil losses. Thermostatically controlled shutters on radiators are helpful in maintaining uniform temperature conditions in the cooling system.[12]

Oil Engines.—Engines designed to operate on fuel oils of lower volatility than gasoline must be equipped with a means of vaporizing the fuel before it enters the engine cylinders, or of injecting it in atomized form at a suitable time in the operating cycle. The earlier types of oil engines, of which there are many thousands now in service, operate on gas oil, kerosene or engine distillate. They are quite similar to the ordinary gasoline engine in design, except that they must incorporate special devices in the form of hot bulbs, tubes or linings to vaporize the fuel. With such fuels, properly vaporized, ignition may be accomplished electrically and with explosive rapidity, as in gas and gasoline engines. For this purpose, spark plugs and a suitably timed system of electrical ignition are employed.

Diesel engines and semidiesel engines, best known and most widely used of the oil-engine group, utilize the heat power of the fuel in a unique way. Instead of exploding a mixture of air and vaporized fuel in the engine cylinder, the fuel burns through an appreciable part of the piston stroke. As a result, the piston moves under the influence of the expansive force of the gases formed by the fuel combustion: a more efficient way of utilizing the heat power of the fuel than by adapting the almost instantaneous impulse of a fuel-air explosion to the stroke of the plunger which, of necessity, must occupy a certain time interval. Thermodynamically, diesel engines are more efficient than any other type of engine, occasionally attaining thermal efficiencies as high as 37 per cent.

For a time, the complex mechanism, high operating pressures and difficulties in starting and speed control, characteristic of the early diesel engines, made them appear impracticable for the character of service required in drilling, but more modern types have largely overcome these difficulties and diesel engines are now widely used in powering rotary drilling rigs. In adapting the oil engine for use with lower grade fuels, such as diesel and other grades of fuel oil, or even crude oil, electrical ignition becomes impossible and must be accomplished by heated vaporizers or high compression and heating of the air used to burn the fuel. In most diesel engines, the fuel is injected in atomized form under high pump pressure, directly into heated and highly compressed air in the engine cylinder. In other cases, the oil first passes through a vaporizing chamber where it is vaporized and ignited before it enters the power cylinders.

Both two-cycle and four-cycle engines of diesel type are available, the method of

operation differing somewhat. The four-cycle diesel engine accomplishes its cycle of operation with two up-and-down strokes of the position. There is one power impulse on every fourth stroke. The first is a suction stroke, during which atmospheric air is drawn into the cylinder through a mechanically controlled valve. On the return or compression stroke, the air valve closes and the piston compresses the air to a pressure of at least 280 lb. per sq. in., raising its temperature to 1000°F. or more. Near the end of the compression stroke, the oil fuel is injected in the form of a spray, under high pump pressure, into this confined charge of heated air, rich in oxygen and, striking the heated metal surfaces, vaporizes and ignites. The time of fuel injection varies with the engine speed and continues during the early part of the third or power stroke. Pressure within the cylinder at the beginning of the power stroke ranges above 475 lb. per sq. in. Combustion is continuous during the injection period, so that the pressure within the cylinder remains nearly constant. After injection of fuel ceases, the remainder of the power stroke is accomplished by further expansion of the gases of combustion. At the end of the power stroke, the exhaust valve opens and the burned gases are displaced from the cylinder on the second return, or fourth stroke.

In operation of a two-cycle diesel engine, air is compressed to a pressure of 450 lb. per sq. in. or more, and a temperature of upward of 950°F. is developed by the compression each time the piston approaches the cylinder head. During the early part of the succeeding power stroke, oil is sprayed into the cylinder under high pump pressure, the heated compressed air ignites the fuel and expansion of the resulting gases of combustion drives the piston away from the cylinder head. Near the end of the power or expansion stroke, movement of the piston uncovers an exhaust port through which the burned gases escape, and a scavenging port through which low-pressure air is forced under pump pressure into the cylinder to drive out the burned gases. While the piston is completing its power stroke and returning on its compression stroke to the point where the exhaust and scavenging ports are again closed by the piston, fresh air enters the cylinder and the air thus introduced is rapidly compressed by the piston as it approaches the cylinder head.

Semidiesel engines utilize the principle of burning the fuel in the engine cylinder during a part of the power stroke but, instead of depending upon highly heated and compressed air to ignite the fuel, this is accomplished by a "hot bulb" or "hot spot" within a recess connecting with the engine cylinder. The hot spot may be a slender metal projection left incandescent by heat of the fuel burned during the preceding stroke. Such an engine may operate under lower pressure than a full diesel engine and may be of lighter construction. During the compression stroke, air is compressed in the cylinder to about 300 lb. per sq. in. Toward the end of this stroke, fuel is injected into the cylinder under high pump pressure, comes into contact with the incandescent hot spot or hot bulb and is ignited. Combustion is more rapid than in the full diesel type of engine. This principle of operation is utilized in both two-cycle and four-cycle engines. They perform more satisfactorily on the lighter and more volatile types of fuel oils.

Diesel and semidiesel engines appropriate for rotary drilling purposes are usually of the vertical, multicylinder type, though a two-cylinder horizontal type has been used to some extent. Four-, six- and eight-cylinder vertical engines are common, with power output ranging from 120 to 150 hp. in light, high-speed models, to large, heavy-duty types developing 300 to 400 hp. and weighing as much as 20,000 lb. They are designed to operate at speeds ranging from 200 to 1,800 r.p.m. and may be equipped with governors that automatically regulate the speed of operation. They are constructed in unitary fashion on steel skids and can be moved from one location to another on a motor truck without any dismantling and can be put in operation within a few hours after arrival in the new location (see Fig. 76). The trend of prefer-

ence appears to be toward low-speed heavy-duty diesel engines of large bore and medium stroke. Though their initial cost is greater than the lighter high-speed engines, they are generally more dependable and require less maintenance. A two-cycle, six-cylinder diesel engine, with cylinders 8¾ in. in diameter and 9½-in. piston stroke, operating at 600 r.p.m., develops 240 brake hp. and weighs 18,500 lb. Two such engines with suitable power-transmission mechanism will be adequate to furnish all power requirements for a rotary rig capable of drilling at depths up to 10,000 ft. In one of the largest mechanical rigs yet assembled, capable of drilling with 4½-in. drill pipe at depths as great as 13,000 ft., the draw works and rotary table are powered with four six-cylinder, vertical engines, each delivering 282 hp. at 900 r.p.m. Two similar engines are provided to drive the slush pumps.[21]

The diesel engine is capable of a wide range of speed control, and speed adjustments can be quickly made. A typical engine may be throttled down to 150 r.p.m. and within a few seconds can be accelerated to its normal operating speed of 650 r.p.m. It has excellent low-speed pulling characteristics in lifting heavy loads, developing increasing torque as the speed is reduced. Important considerations in the design and operation of a diesel engine include provisions for starting the engine when cold. Light, high-speed engines may be equipped with a storage battery and electric starting mechanism. Compressed air may be used in starting heavier, slow- and medium-speed engines. Separate small gasoline-powered engines are sometimes provided for this purpose. Electrical heating plugs are used in starting some models, and often starting the engine may be facilitated by temporarily using gasoline as fuel instead of ordinary diesel fuel. Strainers or filters are generally provided, both for the lubricating oil and fuel entering the engine. Pressure lubrication is provided for all moving parts and presents special problems because of the high temperatures developed. For the same reason, a water-cooling system of ample capacity must be provided and precautions must be taken against scale accumulation in the cylinder jackets. All air used in combustion should be filtered to exclude dust. Cylinders are often equipped with replaceable liners or cylinder sleeves. Special wear- and heat-resisting alloys are used in construction of these liners. Aluminum alloys, used in construction of lightweight pistons, are better able to resist the heat of fuel combustion than cast iron. Many diesel and semidiesel engines are so designed that they can be converted at small cost, to operate on fuels of explosive type—natural gas, gasoline or butane. This involves installation of suitable carbureting and ignition equipment.

Choice of the fuel to be used in diesel-engine operation is an important consideration. Crude oils may be used if clean and not too viscous, but they are not so well adapted as certain refinery distillates, generally marketed under the name of diesel oil. Such distillates generally yield about 19,400 B.t.u. per lb., or 139,800 B.t.u. per gal., and, when burned in a well-designed diesel engine, develop an average of 17 brake hp.-hr. per gal. Important characteristics in a diesel fuel are its ignitibility, combustion knock and ignition lag. High carbon residue is objectionable. The viscosity must not be too high; otherwise it may adversely influence effective fuel atomization. High sulphur content is detrimental. High volatility is objectionable. The percentage of water and suspended solids must be low.

Electric Power Plant for Rotary Drilling

Use of electric motors in rotary drilling is, in reality, merely a means of transmitting and applying power developed by other means. Steam engines, steam turbines or internal-combustion engines are the prime movers by which the power is usually developed and they, in turn, derive

their energy from some type of fuel. Another method of driving electrical generators, of course, is by application of hydraulic energy. The prime mover and electrical generator may be in some distant power plant operated by a utility company; in this case, electricity in the form of alternating current is transmitted to the point of use over high-potential transmission lines. Alternating-current motors are used in drilling equipment at the wells when power is derived from a distant source. Alternating current, often under lower voltage, may also be used in transmitting electrical energy from a central plant situated in or near the oil field where the well is to be drilled, owned in this case perhaps by the oil company conducting the drilling operations. Another plan in which electrical energy is utilized in applying power involves operating an engine-driven generating plant at or near the drilling rig; but in this case, d-c generators and motors are preferably used. Direct-current motors are much better adapted than a-c motors to the type of service required in rotary drilling, approaching steam engines in the flexibility in speed and torque that they afford. Because of the high transmission losses in long-distance transmission of d-c electricity, equipment of this type may be used only when the generating plant is situated near the drilling rig. Another possible plan for converting high-potential alternating current to permit of using d-c motors on the drilling equipment would be to provide an a-c–d-c generator set (an a-c motor driving a d-c generator) at the well; but this would involve additional expense in motor equipment and is seldom if ever employed in rotary drilling. Through the instrumentality of the d-c motor and diesel engine-driven d-c generator, the economy in fuel utilization characteristic of the diesel engine may be combined with the favorable power application characteristics of the d-c motor. A highly efficient, self-contained power plant is thus provided, entirely within the control of the driller.

Use of Alternating-current Motor in Driving Rotary Drilling Rigs.—Where a-c electricity is available for drilling operations, it may be made to serve all necessary power requirements, often at an initial operating cost materially below that possible with steam power. The operator is relieved of the expense and trouble of power development. If the motors selected are sufficiently large, an abundant reserve of power is available for the maximum demand that may be made. Under favorable conditions, progress in drilling may be more rapid and the unit cost may be lower than with steam. There are no cold-weather delays. The control devices available provide a wide range of speed, though at times with some sacrifice of motor efficiency. Electrical equipment is rugged, easy to transport, install and maintain, and problems of water and fuel supply are eliminated. However, one important disadvantage in using a-c motors should be noted. If the power transmission from the distant generator plant should be interrupted unexpectedly, the drilling rig would be left without power, perhaps at a critical time, resulting in costly delays in retrieving "frozen" drill pipe or even jeopardizing future successful completion of the work.

Alternating-current motors used for rotary drilling are of the single-speed, variable-

speed, wound-rotor, induction type which, through the use of suitable control equipment, is reversible and can be operated over a wide range of speeds to adapt it to variable speed and load requirements. The induction motor can be operated at reduced speeds and it can be made to vary its speed as its load varies, the extent of this variation being regulated by a controller and resistor. Drilling motors can exert a very high pulling torque, and their ability to do so in an emergency is often important. The motor increases its pull automatically as the load increases, without any changes or adjustments, and develops its maximum pull at dead stall. Motors of this type usually operate at speeds of 720 to 900 r.p.m. on 60-cycle circuits and at 600 to 750 r.p.m. on 50-cycle circuits. Current is usually supplied at 400 volts, and suitable transformers to step down to this voltage from transmission-line voltage must be provided. Both eight- and ten-pole motors are used, but the latter are in the majority.

The size of motor selected will depend upon the size and weight of the rig to be operated and the depth to be attained in drilling. Motors of 75 and 150 hp. have been widely used; for deeper drilling, 250-hp. motors are employed in driving the draw works while motors of from 200 to 400 hp. drive the slush pumps. Properly geared to the draw works, a 75-hp. motor will meet requirements to a depth of 4,000 ft.; 150-hp. motors up to 7,000 ft.; and 250-hp. motors up to a depth of 10,000 ft. If more power is required, two 150-hp. motors may be arranged to drive the same draw works by the provision of suitable intermediate transmission gear.

A motor capable of handling the heavy hoisting loads in rotary drilling will operate inefficiently under the comparatively light duty of rotating the drill stem. This inefficiency becomes particularly important in large motors used in deep drilling. For such conditions, the star-delta dual-torque motor is well adapted. Such a motor is equipped with special winding that permits it to operate efficiently at half normal load. By simply pressing a button or throwing a switch, which changes the connections on the leads extending out from the motor, a motor capable of delivering 250 hp. is converted to an efficient 125-hp. motor. The higher power is used for hoisting purposes and handling casing and other heavy loads, while for rotating drill stem, making up drill pipe, and other light duties, the motor operates more efficiently on the 125-hp. circuit. In either case, a considerable overload is possible for short periods of time without serious overheating. This is especially important when long strings of heavy drill pipe are being hoisted.

The speed of the drilling motor is controlled by adjusting the amount of resistance placed in series with the secondary or rotor winding of the motor. This adjustment is accomplished magnetically through a bank of grid resistors, regulated by a multipoint master controller which also provides for reversal of the motor. Often an auxiliary controller is supplied, which affords a means of inserting high resistance in the secondary circuit of the motor, thus varying the speed for each point of control on the master controller. One design affords 10 points of control on the master controller and 9 on the auxiliary, thus providing 90 different speeds. This is more than is necessary in rotary drilling, and the auxiliary controller may well be omitted. The controller and resistors are conveniently mounted on a metal frame designed to facilitate moving from one location to another, and can be operated by an endless wire strand passed over a "telegraph wheel" located at the driller's position.

Because of the risk of fire and explosion, owing to possible presence of gas about drilling wells, motors are preferably completely enclosed in fan-ventilated steel housing, and oil-immersed contactors are used in the control mechanism. Overload relays and oil-immersed circuit breakers are provided to protect the motor against damage through overheating.

A rotary drilling rig used in drilling three wells in the Montebello field of Cali-

fornia, powered with a-c motors, uses two 150-hp. motors on the draw works, two 150-hp. motors on one 7¾- by 16-in. slush pump and one 250-hp. motor on another slush pump of similar size. Additional small motors used to operate mud-conditioning equipment, lighting, etc., provided a total connected load of 906 hp. In drilling 22,811 ft. in three wells with this rig, in 149 days (including all erection and dismantling costs on three installations) the power cost per foot of drilling was $0.35; per day, $53.49. Average power cost was $0.01449 per kilowatt-hour.

Use of Direct-current Motors in Driving Rotary Drilling Rigs.—As explained in an earlier paragraph, when d-c motors are used for rotary drilling, the d-c generating equipment, usually driven by means of a diesel engine, is situated at or near the drilling rig. Voltage is highly variable, depending upon the load, and large copper cables or bus bars connect the generators with the rig motors. The primary purpose of such a power plant is to permit the engine to operate continuously at its most efficient speed, using the d-c motor to adapt its power output to serve the variable speed requirements of the rotary drilling equipment. The intermediate electrical generators limit the load that may be imposed on the engine, so that it may never be overloaded or stalled. Variations in load do not injure the generators; when heavily loaded, their voltage is reduced and the speed and torque of the motor are thus automatically adjusted to meet requirements in driving a heavy, slow-speed load or a lighter high-speed load. In hoisting a heavy load, the motor may be stalled and yet the engine will be carrying a lighter load than if the motor were hoisting at its rated speed and power output. Direct-current motors thus have characteristics providing a wide range in speed and torque and are well adapted to meet drilling requirements, either in rotating drill pipe and operating slush pumps, or in hoisting. With two or more engines and generators, it is possible to operate them singly or in combination, in series or in parallel, and apply the power generated to meet the requirements of any individual motor or group of motors as operations may require (see Fig. 77).

Direct-current motors may be either series-wound, shunt-wound or compound-wound. The series-wound motor, in which the field winding is in series with the armature winding, is best for drilling purposes, inasmuch as it is adapted to situations in which high torque is required, and in which rapid fluctuations in torque occur. The speed varies inversely with the load. Such a motor must always be connected positively with its load, for without load it will race and destroy itself. By means of small master switches which permit of cutting the generator fields in or out of service, the voltage is regulated to control motor speed. There are thus a smooth flow of power under all conditions and no power losses by dissipation of energy in resistor grids in controlling motor speeds. Provision is made for low table speeds, quick reversals, fast or slow pickup as required on heavy or light loads, and high hoisting speeds when the hook is not loaded.

In a diesel-electric rig designed for drilling at depths as great as 8,000 ft., two 9- by 12-in., eight-cylinder diesel engines are provided to drive two d-c generators, each rated at 200 kw., with separate exciters rated at 25 kw. In hoisting, the two generators may operate in series, delivering current to the draw works at double their individual voltage, causing the draw-works motor to operate at twice its normal speed. Two 200-kw. generators thus supply 400 hp. for hoisting; and for drilling, one generator furnishes 200 hp. for operating one of the slush pumps and the other 200 hp. for rotating the drill pipe and controlling the draw works.[6]

Where more than two generators are used, parallel operation of the generators is preferable. A modern drilling barge operating in the Gulf Coast region of Louisiana, designed for drilling to depths as great as 12,000 ft., is equipped with four eight-cylinder 9- by 12-in. diesel engines, each delivering 375 hp. at 600 r.p.m. These

engines drive four d-c generators, each rated at 200 kw., 400 volts. Each generator is equipped with a 25-kw. 120-volt exciter, which, in addition to providing excitation for one of the generators, furnishes low-voltage current to operate small auxiliary motors about the rig and for lighting. Each of the two slush pumps, 7¾ by 18 in. in size, is driven by a 400-hp. 400-volt 900-r.p.m. enclosed and ventilated motor. The hoisting motor is of the same size.

POWER-TRANSMISSION MECHANISMS EMPLOYED IN ROTARY DRILLING RIGS

Drilling equipment may be direct-connected to the prime mover or provision must be made for transmission of power generated by the prime mover through some type of intermediate mechanism. Steam-driven slush pumps are often direct-connected. However, power pumps are designed for operation by a mechanical drive, and some type of power-transmission mechanism is always necessary between the engine or motor and the draw works and rotary table. These intermediate mechanisms are necessary to provide for speed reduction and speed variation of the driven machine. They may be mechanical in character—for example, chains and sprockets, belts and sheaves or pulleys, or gearing—or the hydraulic principle of power transmission may be utilized, as in the hydraulic coupling and torque converter.

All power-transmission devices involve the use of steel shafting, and in any mechanism it is highly important that shafting of suitable size and strength shall be employed. Determination of the proper size of shafting for power transmission involves consideration of bending and torsional stresses, as influenced by horsepower to be transmitted, distance of sprockets, pulley or gears from supporting bearings, and pull of belt or chain, weight of pulleys, gears, etc. Shafting may provide a direct connection between the driving and driven machine, in which case both are mounted on the same shaft and rotate at the same speed; or two parallel shafts may be provided to transmit motion, one to the other, through the instrumentality of pulleys, and belts, sprockets and chains, or enmeshing gears. In the latter case, by using pulleys, sprockets or gears of different sizes, the speed of the driven shaft may differ from that of the driving shaft. Bearings for support of shafting are an important consideration. For efficient transmission of power with heavy equipment, roller bearings are used, preferably the self-aligning kind.

When direct drives are used on large, heavy power units, it is usual to protect the prime mover against stresses due to vibration, sudden impact loads and inaccurate alignment of bearings by using two shafts, connected end to end by a flexible coupling. Various types of flexible couplings are available, for example, universal joints, knuckle joints, cushioned joints, disk couplings, roller-chain couplings, etc. Clutches

must be employed to engage or disengage the driven machine from the driving mechanism, and reversing clutches may be used to reverse the motion. This permits of continuous operation of the prime mover in one direction. The modern draw works necessarily incorporates several clutches in its design, and one master clutch must be provided to disengage the prime mover from the machine that it is designed to operate, to facilitate starting of the prime mover while free of its normal load.

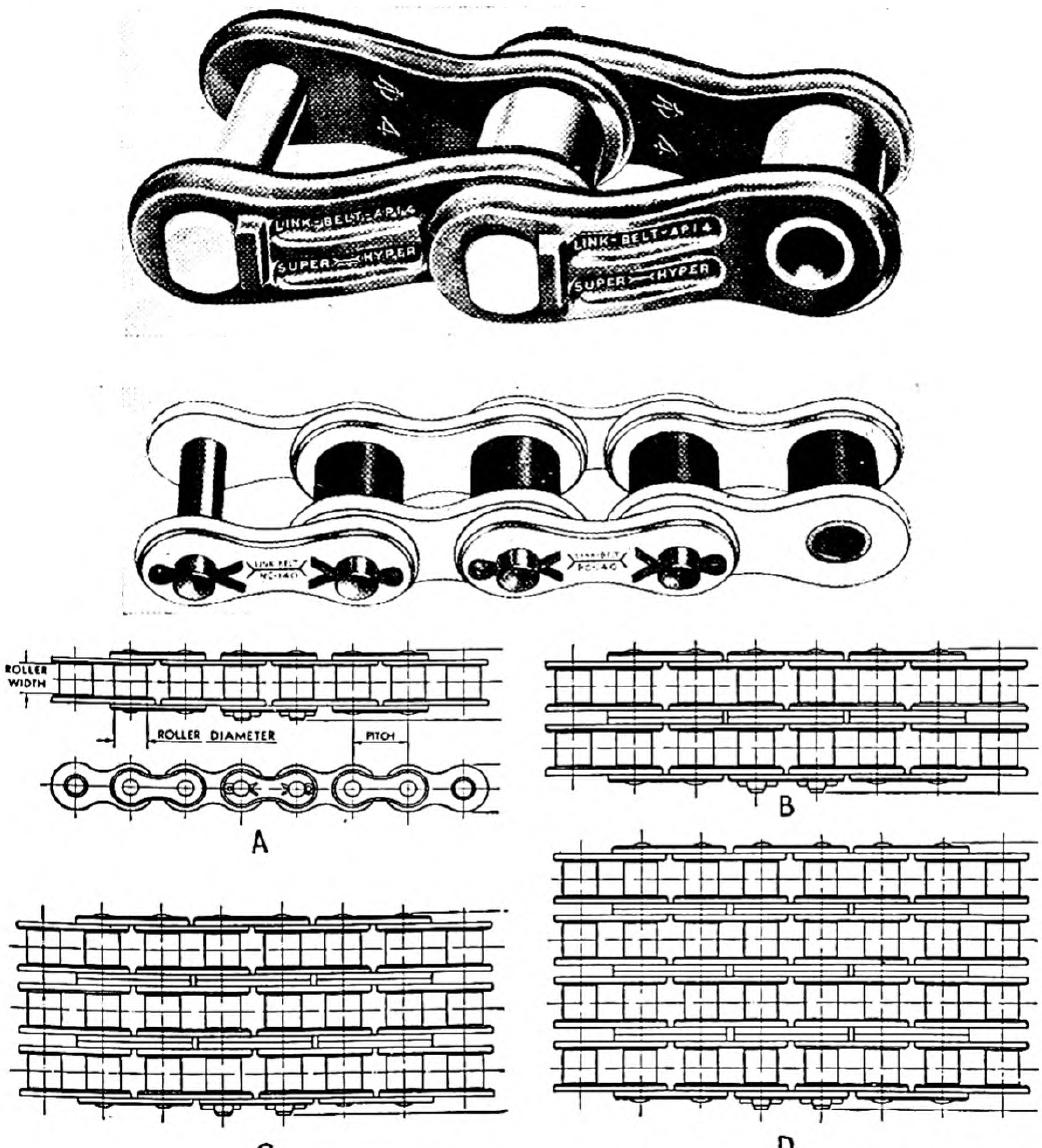
Examples of transmission mechanisms employing these different devices are readily found in rotary drilling equipment. Direct drives are often used between the driving engine or motor and a reversing clutch or speed-reducing gear unit. Chain-and-sprocket drives are nearly always employed between the drive shaft of a steam engine and the line shaft of the draw works, and usually between the draw works and the pinion shaft of the rotary table when the latter is driven through the draw works. Power-driven slush pumps are usually actuated by a belt drive from a pulley on the drive shaft of the engine or motor provided to operate it. For more efficient transmission, such drives are usually of the V-belt type. A gear drive is always provided on the pinion shaft that drives the rotary table, and speed-reducing gear drives are often used between high-speed prime movers and the draw works.

Chain-and-sprocket Drives.—The chain belts that are used for transmitting power between various parts of the rotary drilling rig are of substantial construction and so designed that the chain may readily be disengaged at any link. This is necessary in order to facilitate moving or repairs or to adjust tension, or to get the chain out of the way of operations on the derrick floor when it is not needed. Chain belt is available in several different styles or patterns, usually made of alloy steel. In one commonly used type of chain, the links are made of two separate side bars fastened together at the joints with bushings or barrels, and pins held together by rivets, bolts or cotters (see Fig. 75). The bushings or barrels at the joints take up most of the wear and are easily replaceable. Another type is made of malleable iron, each link being cast separately and the links coupled together to form the chain. Some chains are designed to operate over gear wheels instead of sprockets and are so designed that they present a series of uniformly spaced projecting cogs on the inner side of the belt.

Chain drives may consist of a single chain of links, or of two or more chains connected side to side to form double-, triple- or quadruple-chain belts. "Roller chain," operating with less friction and noise, is assembled with a loosely fitting steel roller about the pin that holds the side bars together at each joint (see Fig. 75). Built to a variety of different pitches, heavy patterns of single chain have breaking strengths as great as 185,000 lb., while multiple chains may carry correspondingly greater loads. The A.P.I. has adopted standard specifications for chain belts to which most manufacturers adhere. Thus, chains made by different manufacturers to meet particular specifications are interchangeable.

Sprockets designed to operate with chain belt are usually of cast steel with machine-cut teeth. For smoothness in operation, a sprocket should have at least 15 teeth and the recommended maximum speed ratio between driving and driven shaft is 8 to 1. Chain-driven sprockets may be closely spaced, the minimum distance diminishing with the pitch of the chain. The chain should have at least 120 deg. of contact with

the sprockets. Chain drives must be operated with a certain amount of slack over the sprockets; otherwise they bind, make considerable noise and power is wasted in unnecessary friction. On the other hand, chains that are too loose will whip excessively and cause rapid wear.



(Courtesy of Diamond Chain & Mfg. Co., and Link-Belt Co.)

FIG. 75.—Types of chains used in chain-and-sprocket drives. *A*, single chain; *B*, double chain; *C*, triple chain; *D*, quadruple chain.

Chain drives must be lubricated properly to reduce friction, noise and wear on the links, pins, rollers and sprockets. The lubricant used is preferably a good grade of machine oil having a viscosity of about S.A.E. 30 or 40, but may be varied to accord with weather conditions. Very heavy oils or greases should not be used as they fail

to reach the parts that need lubrication. Oiltight chain guards make possible forced lubrication under pump pressure. Steel housing over chain belts is often designed to intercept oil thrown from the chain during its operation and accumulate it at certain points so that it again falls on the moving chain. Sight-feed drip cups are also used to drop oil in regulated amount on the moving chain, or it may be swabbed with oil when lubrication becomes necessary. Chains should occasionally be removed from the sprockets, soaked in distillate and cleaned to remove grease and accumulated dirt.[9]

Multiple V-belt Drives.—Slippage is an important source of wear and mechanical inefficiency in operating flat belts on flat or crowned pulleys. Where a belt drive is desirable, especially in driving heavily loaded, rapidly revolving shafts, V belts are usually preferable and are frequently used on rotary drilling equipment. The V belt is made of cord and fabric embedded in rubber, molded to form a continuous belt of "keystone" cross section, and is designed to fit in grooves of similar form cut in the rims of the sheaves over which they operate. Each belt of a given cross section is capable of transmitting a certain horsepower at a given speed, and a series of closely spaced belts, each operating in a separate pair of grooves on the sheaves, provides a means of transmitting whatever power may be required. The speed of travel of a V belt should preferably not exceed 5,000 ft. per min. A "cog belt" is a special variety of V belt designed to operate over a gear wheel instead of a sheave.

Hydraulic Power-transmission Devices.—Modern rotary drilling rigs, especially those driven by internal-combustion engines, occasionally utilize hydraulic devices of the turbo type for relieving the engine of shock loads and as a means of adapting the constant operating characteristics of the prime mover to the variable speed and torque requirements of the drilling equipment. The hydraulic coupling and hydraulic torque converter are two essentially different devices utilizing the hydraulic principle that have found application in transmission of power to rotary drilling equipment. Both of these devices comprise a centrifugal pump, rotated by the engine drive shaft, and a coaxially mounted reaction turbine, mounted on the secondary or driven shaft, both enclosed in a steel housing filled or partly filled by a liquid—usually oil.

In the hydraulic coupling, the fluid is confined within the housing that surrounds the pump and turbine, and merely provides a medium for transmitting force from one to the other. As the pump impeller is rotated, centrifugal force tends to drive the oil directly into the vanes of the runner of the reaction turbine facing it, so that both revolve together. There is necessarily some slippage, the amount depending upon the rotational speed and the load on the driven shaft. The speed and horsepower output of the driven shaft is therefore always somewhat lower than that of the engine shaft. The input torque is always equal to the output torque except for inherent frictional losses. The torque characteristics of the prime mover are not altered; that is, there will be low torque at slow speeds and high torque at higher speeds and the output torque can only be altered by changing the speed of the prime mover. When subjected to sudden overload, the slippage between the pump and turbine increases, so that the engine may continue to operate, though at gradually reduced speed. In case of an extreme overload, the driven shaft may be stalled and yet slippage in the coupling will permit the engine to continue operating in its lower speed range. Hydraulic couplings are not usually designed for use in service where continuous variation in slippage between the rotating elements is required. Where such service is imposed, the fluid absorbs heat, and provision must be made for cooling it. Convection from the coupling housing will take care of the heat generated by the relatively small continuous slippage that occurs when both input and output shafts are moving at their normal speed ratio. Various types of hydraulic couplings are available. In one type, provision is made for quickly changing the volume of oil in the chamber in which the rotating elements operate, thus introducing an additional element of control. So

responsive is this device to slight changes in the amount of oil between the rotating elements, that with suitable controls the coupling may be used as a clutch. However, no hydraulic device of turbo type can be expected entirely to replace the mechanical clutch, which must also be provided.

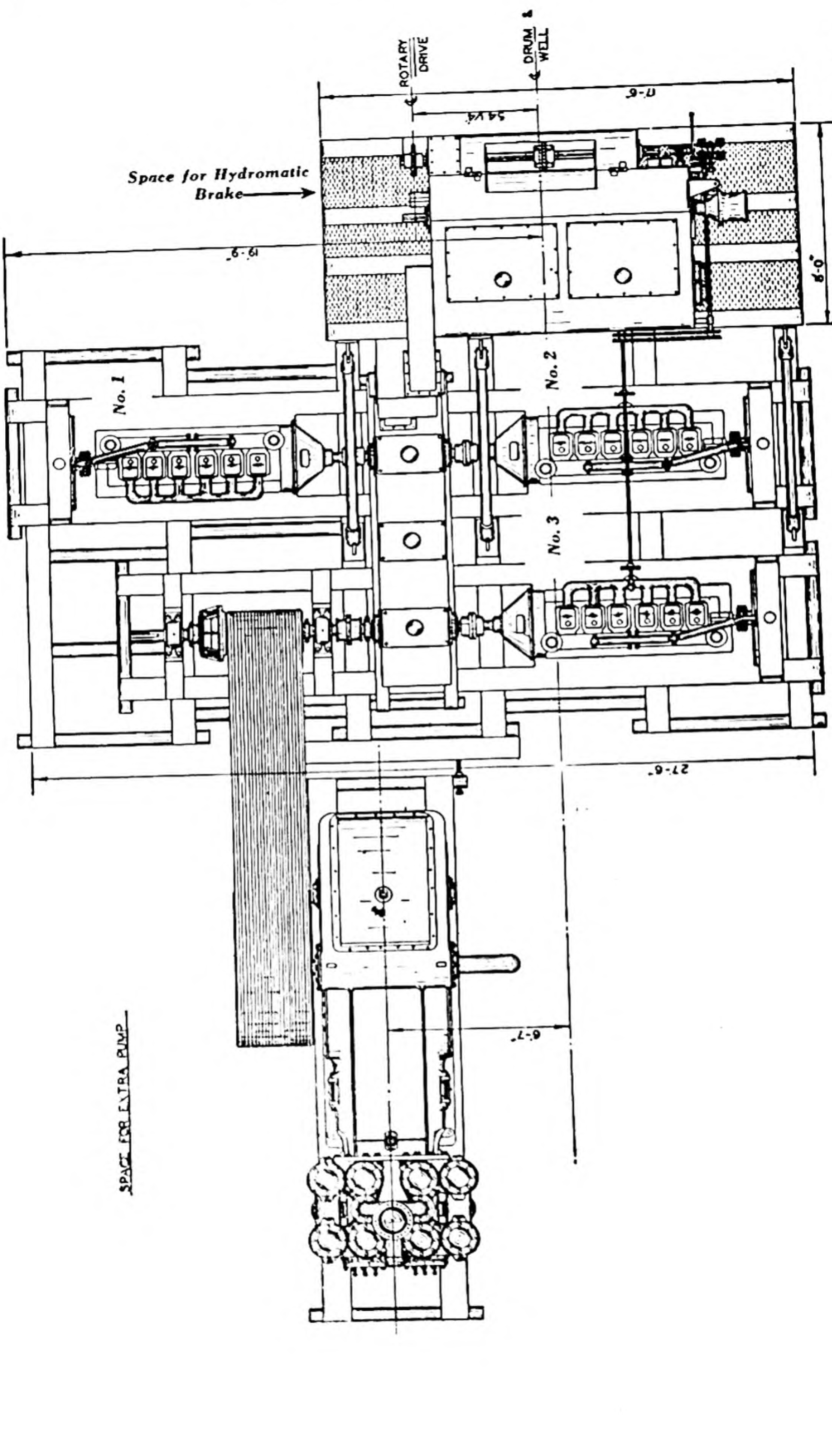
Like the hydraulic coupling, the torque converter employs a coaxially mounted centrifugal pump and reaction turbine, mounted in a suitable housing, but in this device, provision is made for the intervening liquid to flow between the vanes of the revolving elements. The kinetic energy imparted to the fluid by the centrifugal pump is employed to drive the turbine. In this device, owing to continuous change in the direction of flow of the fluid, a reaction against the enclosing steel housing permits an increase in torque on the driven shaft. The converter may comprise a single pair of opposing impellers or a multiple of stages with fluid flowing from one to the next in series. Like the hydraulic coupling, the torque converter dampens the effect of shock loads on the prime mover by slippage of fluid between the rotating elements, but in addition it provides a means of varying the torque ratio between the driving and driven shafts over a wide range. Impellers of the pump are so arranged that if the load increases, the torque delivered to the driven shaft is automatically increased. Methods of accomplishing this vary in different designs, but in one type a gear mechanism responsive to load changes alters the pitch of the pump impeller blades.[27]

In comparing the merits of the hydraulic coupling and the torque converter for transmission of power to rotary drilling equipment, it is apparent that the coupling is well adapted to constant-speed installations where slippage is not continuous or erratic, and is required only to compensate for shock loads and occasional overloads. Its output torque is limited to the input torque. The torque converter, on the other hand, is well adapted to variable-speed requirements in which loads are highly variable or are started and stopped frequently, and when high torques at low speeds are desirable in lifting heavy loads. It provides a flexibility of control approaching that of the steam engine or the d-c motor, protecting the engine against shock loads and torsional vibration, and assuring smooth starting and acceleration of heavy loads.

Hydraulic couplings have been advantageously used in driving slush pumps with internal-combustion engines. Here they are used primarily to protect the engine against sudden overloads when the pump becomes stalled by some interruption in the drilling fluid circuit. Torque converters are useful in transmitting power from internal-combustion engines to the draw works and are helpful in adapting this type of prime mover to heavy, variable-speed hoisting service. The converter is also useful in adapting a direct-engine drive to the rotary table. Torque converters would perhaps also be adaptable to situations where a-c motors are employed in driving rotary drilling equipment.

Speed-reduction Gears.—Internal-combustion engines and electric motors have operating speeds too high to permit of connecting them directly with rotary drilling equipment. To reduce rotational speeds to those appropriate for driving a rotary table, draw works or slush pump, a reduction-gear mechanism is often inserted between the engine or motor and the equipment to be operated.

A typical drilling reduction gear comprises two helical gears enclosed in an oil-tight housing, with a self-aligning flexible coupling for connecting with the engine or motor drive shaft. On the output, low-speed shaft is mounted a sprocket designed for a double-chain drive to the draw works. Splash lubrication is used, and in operation the gears are constantly flooded with oil. The gears provide a speed ratio of 3.12:1, as between the input and output shafts. Equipped with roller bearings, this reduction gear is capable of transmitting power from a 250-hp. a-c motor. Such a reduction gear weighs about 10,000 lb.



(Courtesy of Portable Rig Co., Inc.)

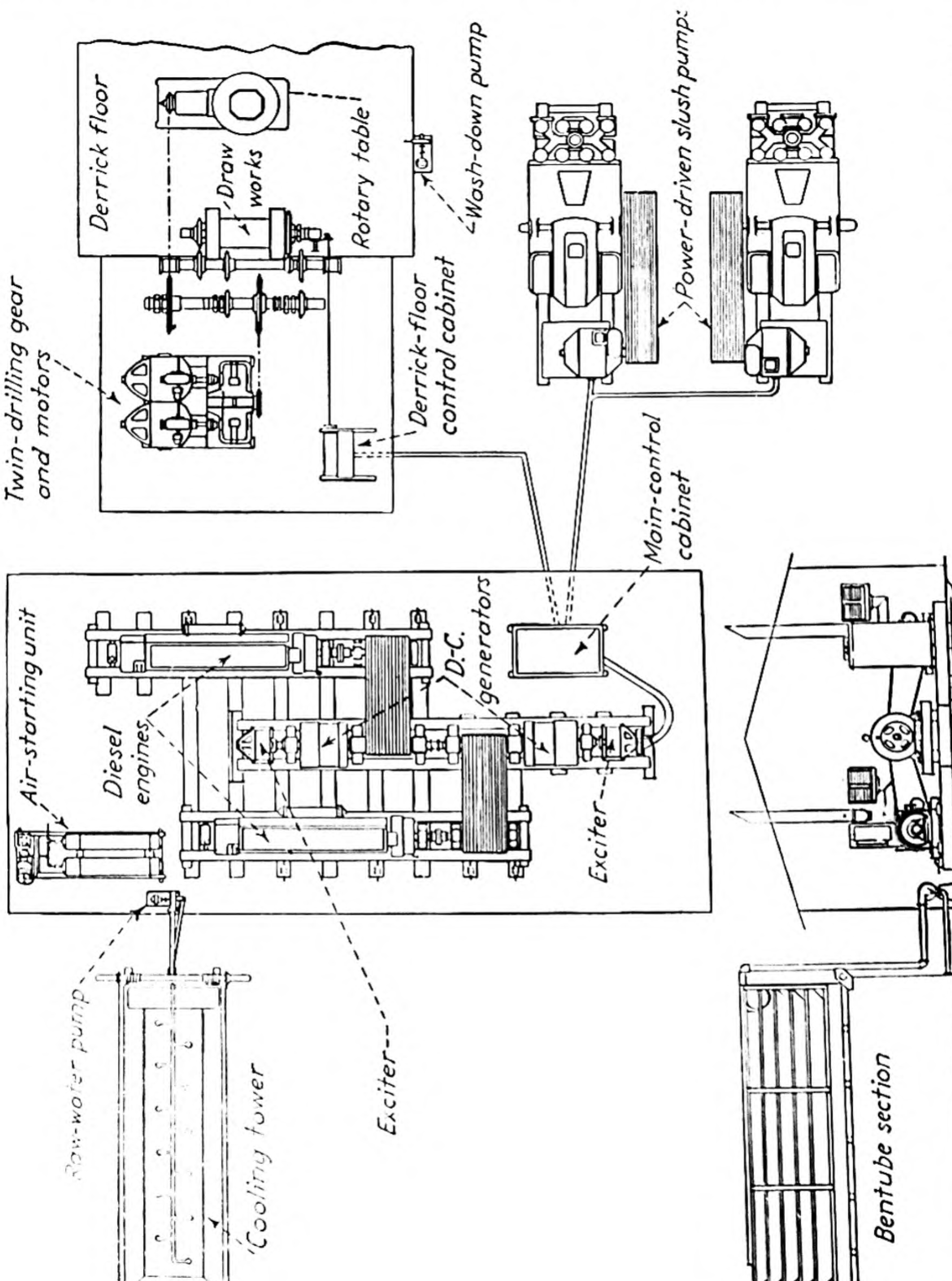
FIG. 76.—Skid-type portable rotary drilling rig.

Multiple-engine Drives.—Large, heavy-duty rotary drilling rigs, designed for deep drilling, often require the combined output of two or more engines, and provision must be made for manifolding the output of the power units into a single, mechanical drive to the draw works, and usually, also, to provide for operation of one or more slush pumps and the rotary table. The mechanisms required will, of course, vary with the number of prime movers employed and the connections necessary, and may include a variety of power-transmission devices, including shafting with necessary bearings and supports, flexible couplings, V-belt or chain drives, clutches, etc. The design generally contemplates a certain degree of flexibility, so that any one prime mover may be used alone or in combination with others, and so that the flow of power may be directed to one part of the rig or another as conditions may require.

Many different hookups are possible, but Fig. 76 presents a typical arrangement of transmission mechanisms to drive all parts of a rotary rig with three internal-combustion engines. The engines are grouped together and their drive shafts connect through flexible couplings and friction clutches to drives connecting each engine with either or both of two shafts, on one of which is mounted a sheave that supports a V-belt drive to a power-driven slush pump, while the other supports sprockets for a triple-chain drive to an oil-bath transmission unit, incorporated in the unitary construction of the draw works. The two drive shafts are also connected by a chain drive. On the input shaft to the transmission unit, a master clutch is mounted that permits of engaging or disengaging the power from the draw works and rotary table. The transmission unit comprises two shafts with a series of sprockets and chains with necessary clutches to provide three forward speeds to the draw works, while a pair of gears with clutch control provides for reverse motion. With additional speed controls afforded by chain-and-sprocket drives between the line shaft and drum shaft of the draw works, the driller has a choice of six hoisting speeds. The rotary table is driven by a chain-and-sprocket drive from the drum shaft, through a countershaft equipped with a friction clutch. Three speeds are provided for the rotary table. By these arrangements, when drilling is in progress, one engine drives the slush pump while the others provide power for the rotary table and draw works. When drawing out drill pipe, the engines are compounded through the connections described, so that their combined power output is transmitted to the hoisting drum.

Diesel-electric Drives.—Simplicity of arrangements when d-c electricity is used as a means of transmitting internal-combustion engine power to a rotary drilling rig is well exemplified by Fig. 77. Here two 350-hp. 8-cylinder engines, 9 by 12 in. in size, operating at a normal speed of 600 r.p.m., deliver their power through suitable clutches, flexible couplings and V-belt drives to two d-c generators, each with its own exciter. One generator develops 200 kw. at 200 volts when turning at 1,200 r.p.m., while the other is a 250-kw. machine operating at the same speed and delivering current at the same voltage. The generators are mounted in line, with a coupling between, so that either or both can be operated by either of the two engines or by both engines. A small engine-driven compressor with two compressed-air receivers is provided for starting the diesel engines and a small centrifugal pump and louver tower for cooling the water used in the engine jackets. The power plant may be at any convenient location near the drilling rig. Direct current passes through a control panel and heavy copper cables in conduits leading to the motors provided for driving the drilling equipment. A second control panel in the rig affords a means of switching current on or off at the various motors as circumstances may require. Two 200-hp. 200/400-volt, 450/900-r.p.m. d-c motors are connected through a twin reduction gear (gear ratio 3.12:1) to the jackshaft of the draw works by a chain-and-sprocket drive. Both the hoisting drum and the rotary table are driven from the draw-works jackshaft by chain-and-sprocket drives. Either motor may be used

separately to drive the draw works and rotary table, or both may be used together if circumstances require more power than one motor can furnish. With 200-volt current, each motor rotates at 450 r.p.m. and delivers 200 hp. The two drilling



(Courtesy of National Supply Co.)

FIG. 77.—Layout of power plant for diesel-electric drive of rotary drilling rig.

motors may be replaced by one double-rated motor and a single-reduction gear. Operating on 200-volt current, this motor revolves at 450 r.p.m. and delivers 200 hp.; with 400-volt current, obtained by operating the generators in series, the motor turns

over at 900 r.p.m. and delivers 400 hp. Each of the two power-driven slush pumps is equipped with a separately controlled d-c motor of from 200 to 300 hp. (as conditions may require) with suitable reduction gear and V-belt drive. These motors operate on 200-volt current and rotate at 900 r.p.m. The pumps normally operate at 45 to 55 strokes per minute. The Wood-Leonard control system affords a wide range of speed variation for the motors, providing for all operating conditions.[19]

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CHAPTER VII

ROTARY DRILLING EQUIPMENT

In Chap. IV, it was explained that there are at least two fundamentally different types of rotary drilling equipment, but one of these—the mechanically controlled rotary equipment—has been used in drilling oil and gas wells more than the others. As the name indicates, with the mechanically controlled rotary equipment, the rate of penetration of the drill is regulated through the instrumentality of mechanical devices which may be either manually or automatically controlled. With the hydraulic system, the rate of penetration is regulated by fluid pressure. The present chapter will be devoted to a description of the conventional mechanically controlled type of rotary equipment. The hydraulic systems of control will be described in Chap. X. The circulating system and its control, applicable to all types of rotary equipment, will be discussed in Chap. VIII, and the operation and control of the rotary equipment in the routine of drilling will be the topic of Chap. IX.

MECHANICALLY CONTROLLED HYDRAULIC ROTARY EQUIPMENT

In any discussion of the mechanical features of rotary drilling, one should realize that there is considerable variation in structural detail and, of course, important differences in size and weight of component parts in accordance with the depth to which the equipment is designed to drill. Then, too, there are marked differences in design that are a result of progressive improvements and the introduction of new features. An historical review, sketching the development of rotary drilling equipment over a period of, say, 40 years, would show revolutionary changes; and some of the most drastic changes in design have come during recent years and are still continuing. Although most drilling equipment has a comparatively short life—perhaps 5 to 10 years—some of the equipment currently used in the industry is much older. Accordingly, at a given time, one may expect to find a variety of different styles and types of equipment in current use. In the discussion to follow, an effort will be made to acquaint the reader in some degree with the historical evolution of different styles of rotary drilling equipment, emphasizing in descriptive detail the more modern, currently manufactured types. In considering the latter, light, medium and

heavy styles will be described, designed, respectively, for drilling to depths of less than 5,000 ft., 5,000 to 10,000 ft., and depths in excess of 10,000 ft.

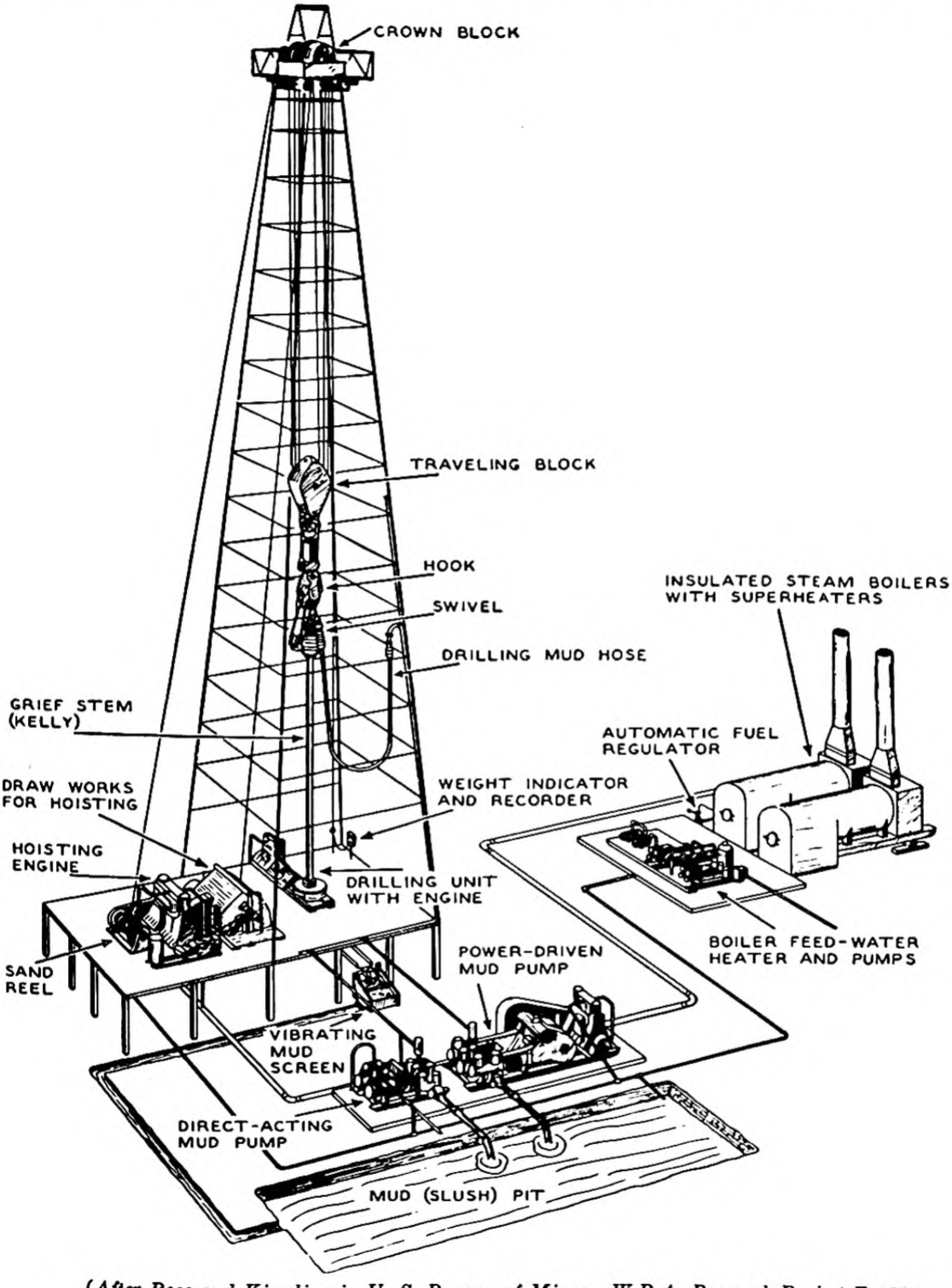
Hoisting Gear

According to the functional classification suggested on page 203, the third group of component elements of the rotary drilling rig with which we have to deal is the equipment used in supporting the drill column and handling drill pipe and other heavy loads in the derrick. This includes the draw works, the crown block, the hoisting block and hook and the hoisting cable. These elements should be carefully selected, so that they are of equal strength and capacity and so that they will function collectively to perform a specified maximum hoisting duty without failure of any component part. The loads to be handled in heavy-duty rigs designed for deep-well drilling may aggregate 100 tons or more and the equipment may be called upon to transmit and apply as much as 2,000 hp. Consequently, this part of the equipment must be rugged and massive in its proportions, yet mechanically well designed and accurately constructed to operate with minimum frictional loss and provide the necessary delicacy of control.

Figure 78 illustrates a common arrangement of the several elements of the hoisting gear in a conventional rotary drilling rig. The draw works, situated at one side of the derrick floor, is connected with a steam engine or other source of power by a chain-and-sprocket drive. The draw works embodies a hoisting drum with suitable clutches and speed-reducing mechanisms to regulate the hoisting speed, and powerful brakes to control rotation of the drum under load. One end of the hoisting cable is attached to and wound around the hoisting drum. The other is carried up through the derrick, passed over one of the several sheaves in the crown block, thence back and forth between sheaves of the hoisting block, suspended in the derrick, and other sheaves of the crown block. The dead end of the hoisting cable is attached to the upper bail of the hoisting block or to one of the derrick sills; or, in some of the less common arrangements of equipment, it may be wound on the shaft of a calf wheel (in a combination rig), or on the hoisting drum of an auxiliary draw works. The hoisting hook is suspended from the lower bail of the hoisting block.

The Draw Works.—The draw works serves as a power-control center for the hoisting gear and usually, also, for the rotary elements of the drill column. It comprises a hoisting drum, controlled by powerful brakes, and an assemblage of shafts with supporting bearings, clutches and sprockets with chain drive, to receive power from an engine or motor and to regulate the speed of the hoisting drum. A chain-and-

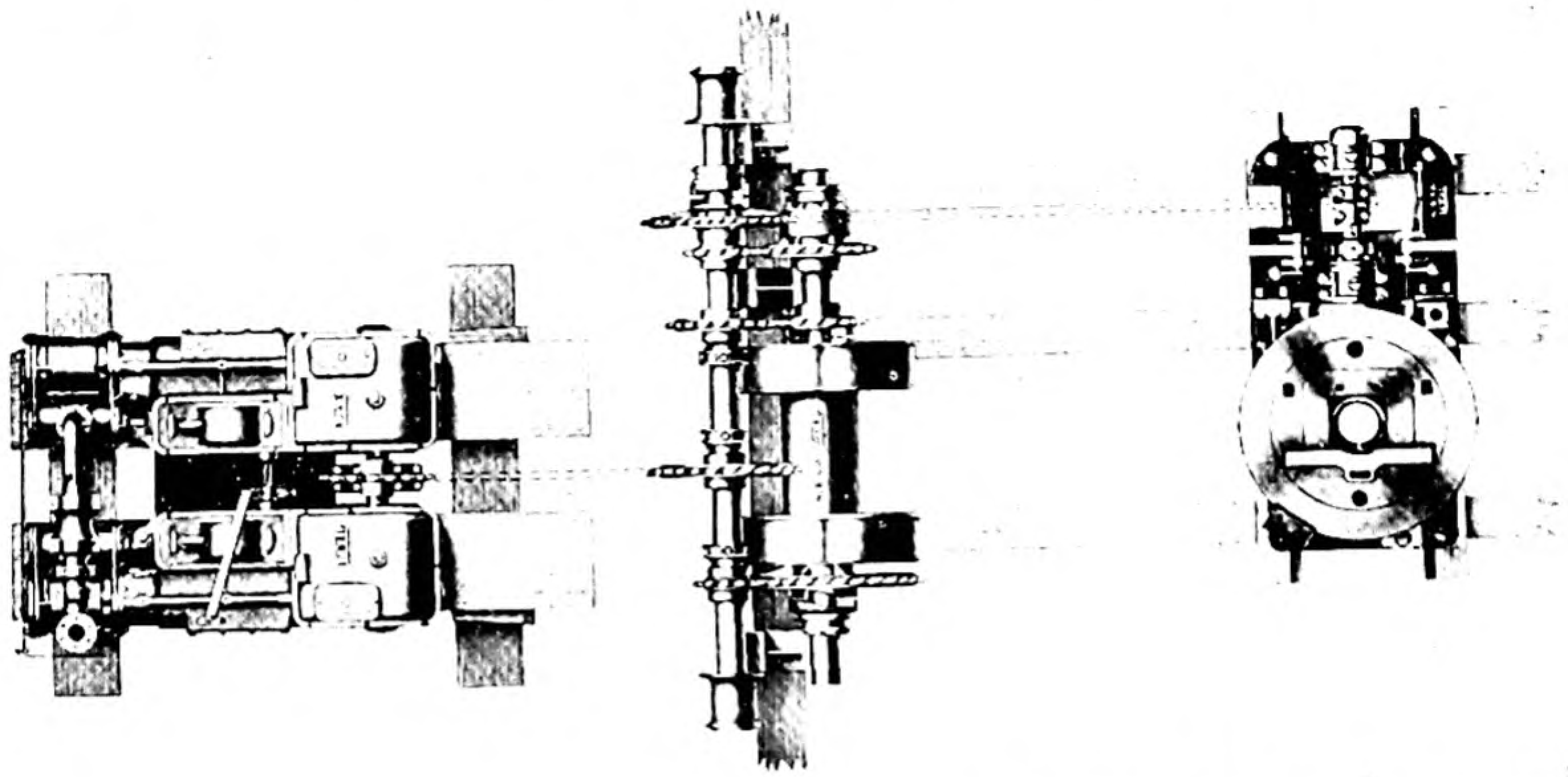
sprocket drive with suitable clutch control is usually also provided on one shaft of the draw works to drive the rotary table (see Fig. 79). The



(*After Ross and Kiessling in U. S. Bureau of Mines—W.P.A. Research Project E-126.*)
FIG. 78.—Sketch showing relation of parts of a modern rotary drilling rig.

component parts are supported by bearings mounted on opposite sides of supporting posts of steel or heavy timber, two or three in number, that are bolted in one of the "windows" of the derrick. In the more

modern types of draw works, the shafts are supported on bearings attached to a steel A frame mounted, unitary fashion, on steel skids.

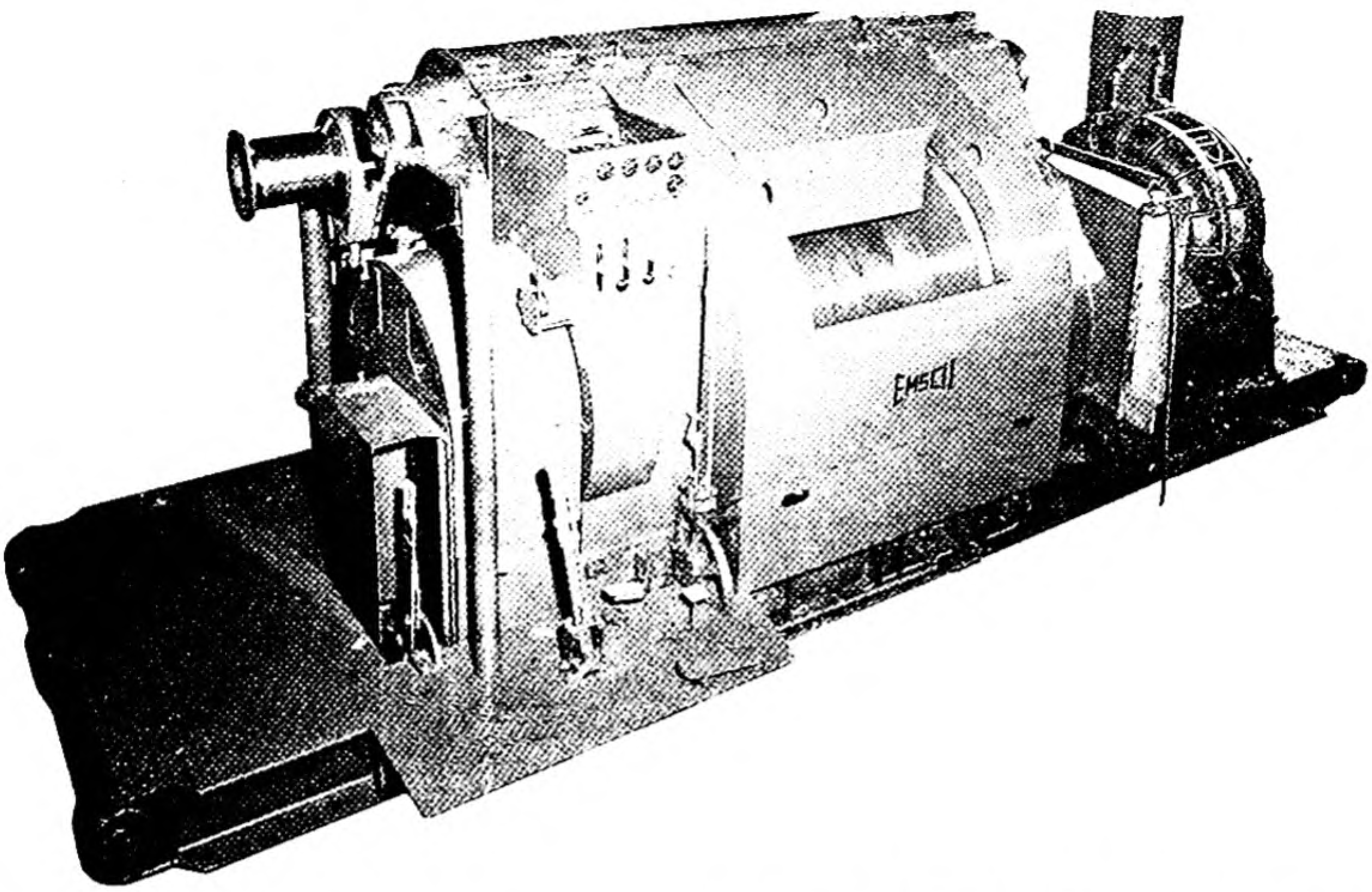


(*Courtesy of National Supply Co.*)

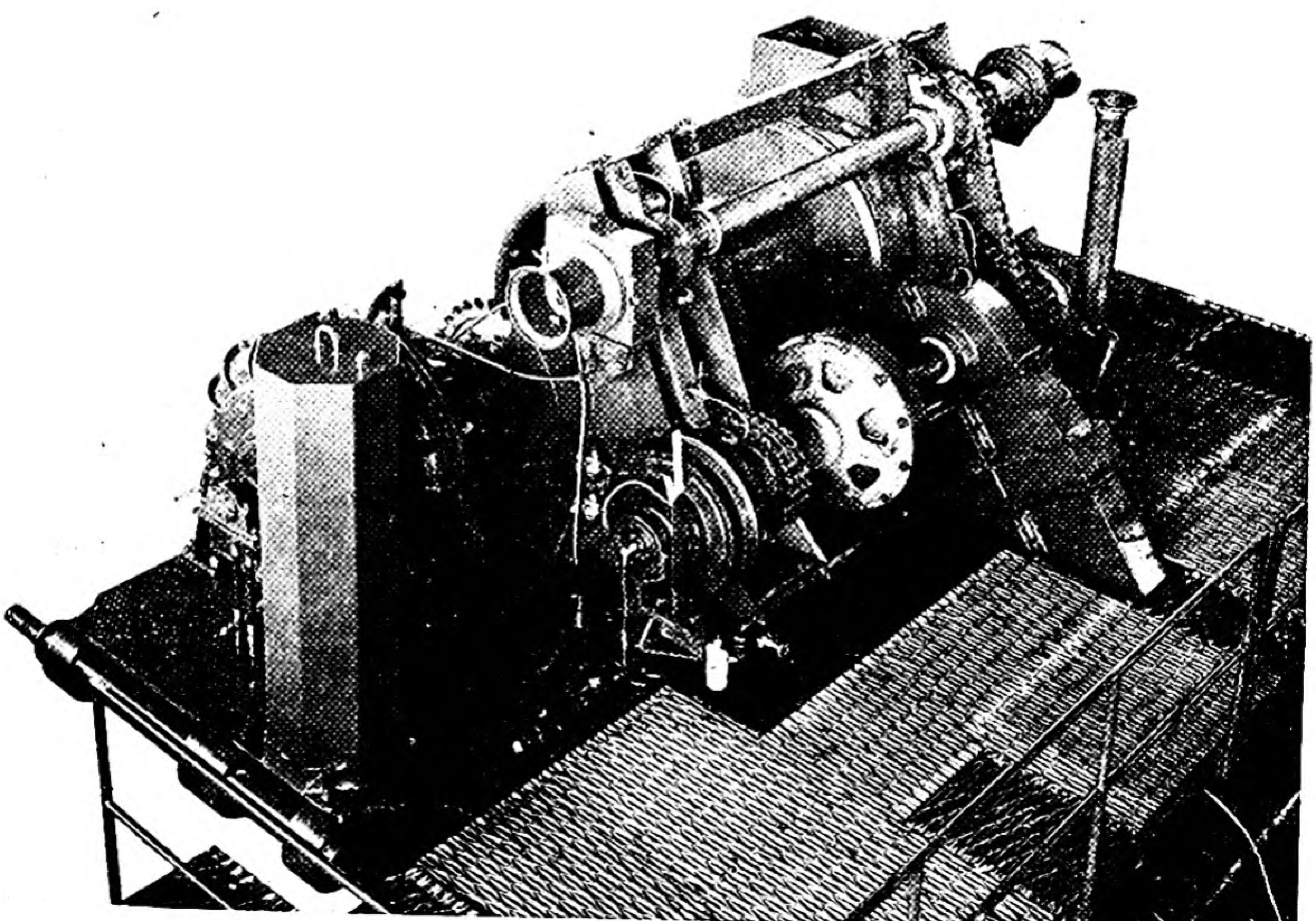
FIG. 79.—Plan view of rotary drilling equipment showing twin-cylinder steam engine, three-speed draw works and chain-driven rotary table.

Draw works are available from different manufacturers in a variety of styles, weights and sizes, designed for two, three, four, six or eight hoisting speeds. In deeper drilling the draw works is, of necessity, made heavy and powerful in order to deal with the heavy loads imposed. The modern draw works is also considerably more complex than the more primitive designs of earlier years. This has resulted primarily from the necessity for providing a greater range of speed control. Drilling to shallow or moderate depths may be conducted satisfactorily with a light and mechanically simple and comparatively inexpensive two- or three-speed draw works utilizing only two shafts: a line shaft and a drum shaft. Early models were of this type. The heavier loads imposed in deeper drilling require greater flexibility in speed and power control afforded by the four-, six-, or eight-speed types, in which a jack shaft is provided in addition to the line and drum shafts.

Figures 80 and 81 illustrate a modern, heavy-duty, three-shaft, four-speed draw works designed for drilling to depths as great as 12,500 ft. Figure 80 is a reproduction of a photograph showing a front view of the draw works as it appears in working position with all steel housing guards installed. Figure 81 is a rear view, with guards removed. Figures 82, 83 and 84 are drawings presenting, respectively, a plan or top view, an end elevation and a front elevation of a somewhat heavier draw works designed for drilling to 14,000 ft. With reference to the drawings and the speed diagram reproduced in Fig. 85, double sprocket 1, on jackshaft 2, is connected by a double chain with the engine drive sprocket. Two sprockets, 3 and 4, mounted on the jackshaft with their clutch controls, permit of selectively using one or the other. These are connected by a double-chain drive, respectively, to sprockets 5 and 6 on line shaft 7. The jackshaft and line shaft are $8\frac{1}{2}$ in. in diameter. Sprockets 3 and 5 provide the low-speed drive to the line shaft, and sprockets 4 and 6 provide the high-speed drive. Keyed to the line shaft and turning with it, sprockets 8 and 9 provide high- and low-speed connections, respectively, to double sprockets 10 and 11, mounted on the drum shaft 12. This is 9 in. in diameter. Lever controls



(*Courtesy of Emsco Derrick & Equipment Co.*)
FIG. 80.—Heavy-duty draw works suitable for drilling to depths as great as 12,000 ft.



(*Courtesy of Emsco Derrick & Equipment Co.*)
FIG. 81.—Heavy-duty draw works, rear view, guards removed.

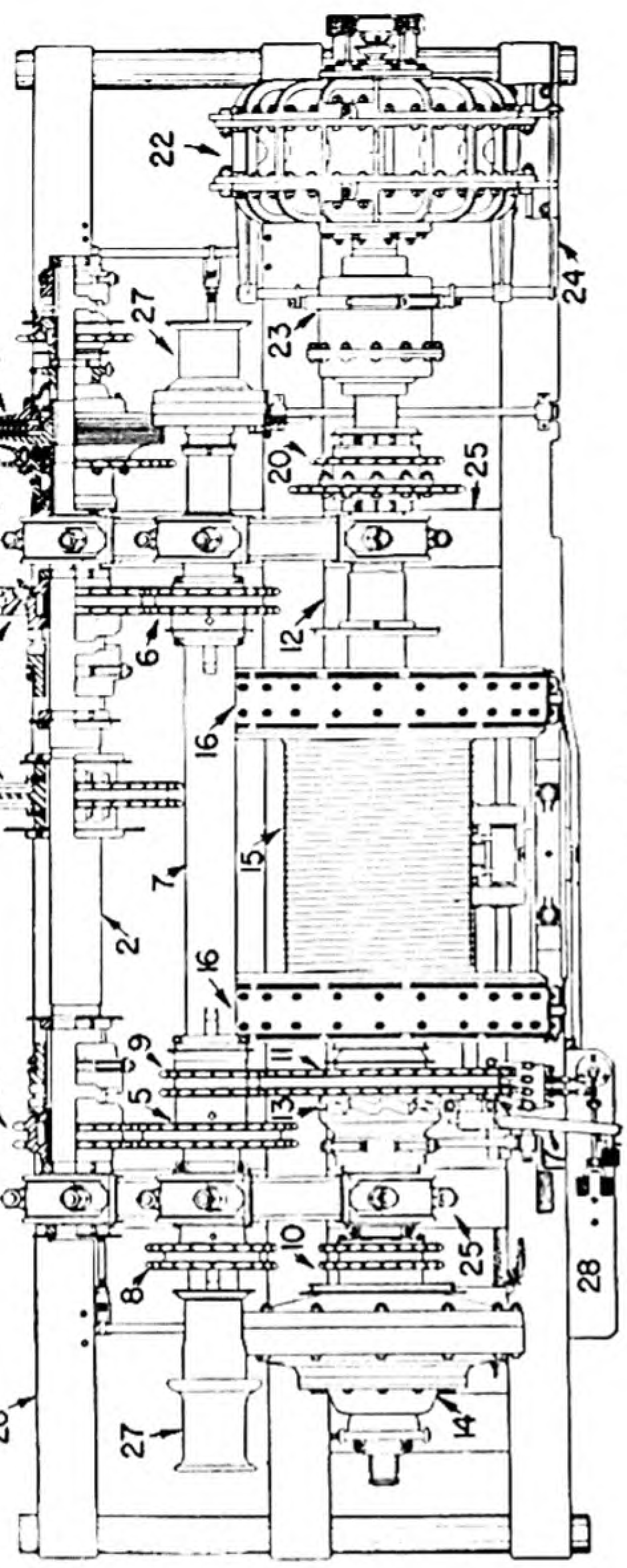


FIG. 82.—Plan view.

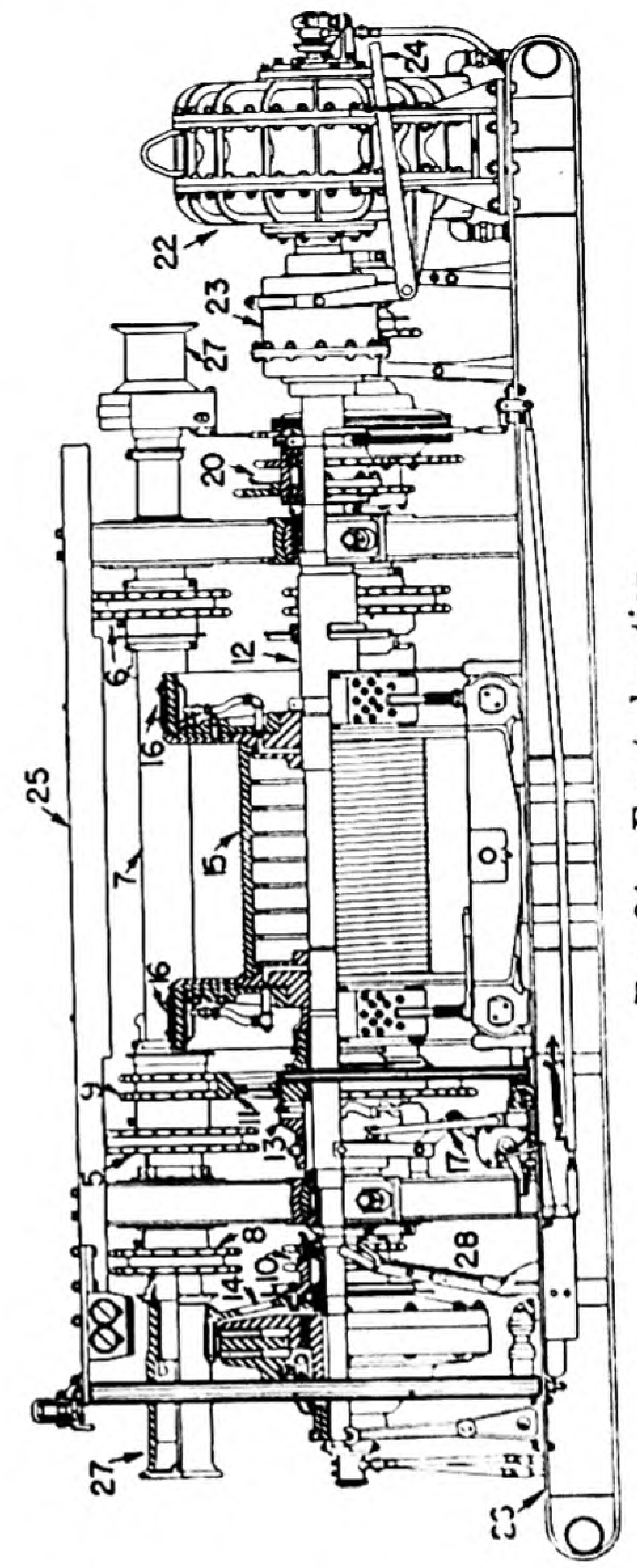


FIG. 84.—Front elevation.

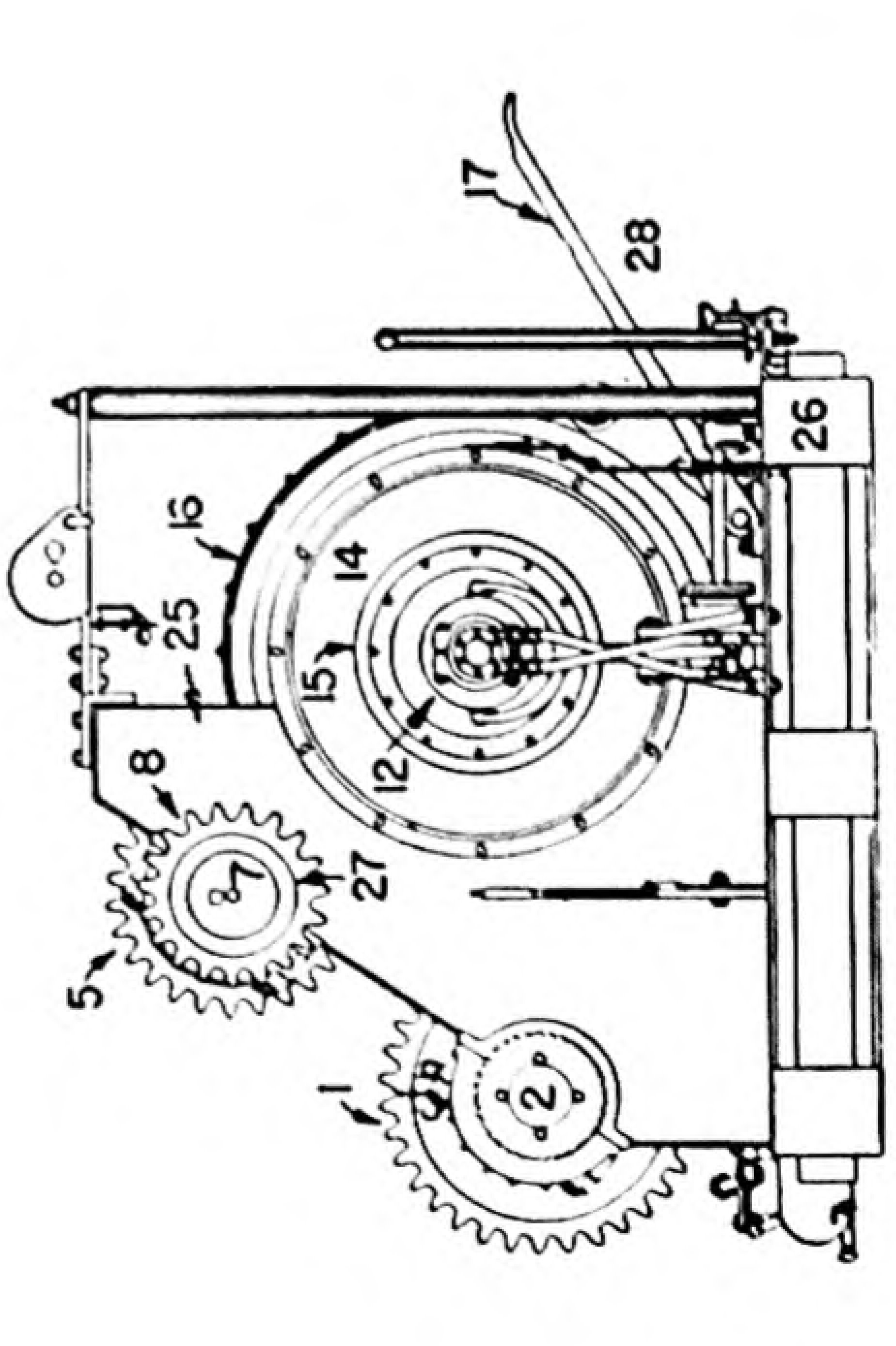


FIG. 83.—End elevation.

Heavy-duty draw works.
(Courtesy of Emsco Derrick & Equipment Co.)

operate a multiple-jaw clutch 13, and an hydraulically actuated friction clutch 14, permitting the driller to apply either the low- or high-speed drive from the line shaft to the drum shaft.

The speed diagram (Fig. 85) indicates the number of teeth in each of the sprockets and the rotational speeds possible for each of the three shafts with the several possible combinations of sprockets afforded by the clutch controls. It will be noted that with an engine-sprocket speed of 200 r.p.m., speeds of either 57, 96, 172 or 291 r.p.m. are provided for the drum shaft. The grooved hoisting drum, 15, is 30⅝ in. in

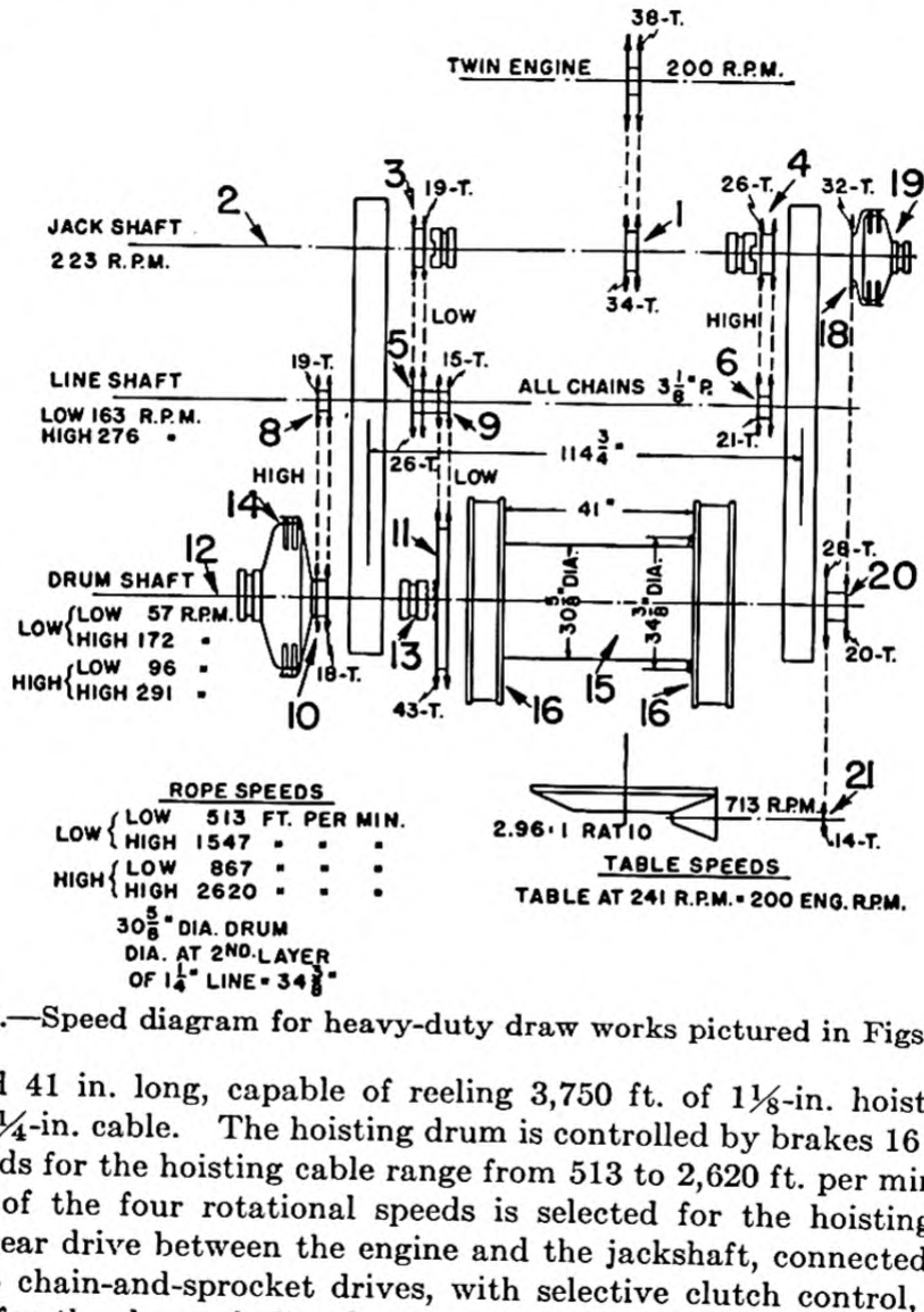


FIG. 85.—Speed diagram for heavy-duty draw works pictured in Figs. 82–84.

diameter and 41 in. long, capable of reeling 3,750 ft. of 1⅛-in. hoisting cable, or 3,060 ft. of 1¼-in. cable. The hoisting drum is controlled by brakes 16 and lever 17. Possible speeds for the hoisting cable range from 513 to 2,620 ft. per min., depending upon which of the four rotational speeds is selected for the hoisting drum. By installing a gear drive between the engine and the jackshaft, connected to the jackshaft by two chain-and-sprocket drives, with selective clutch control, eight speeds are possible for the drum shaft. Such an arrangement is desirable when internal-combustion engines are used as the source of power.

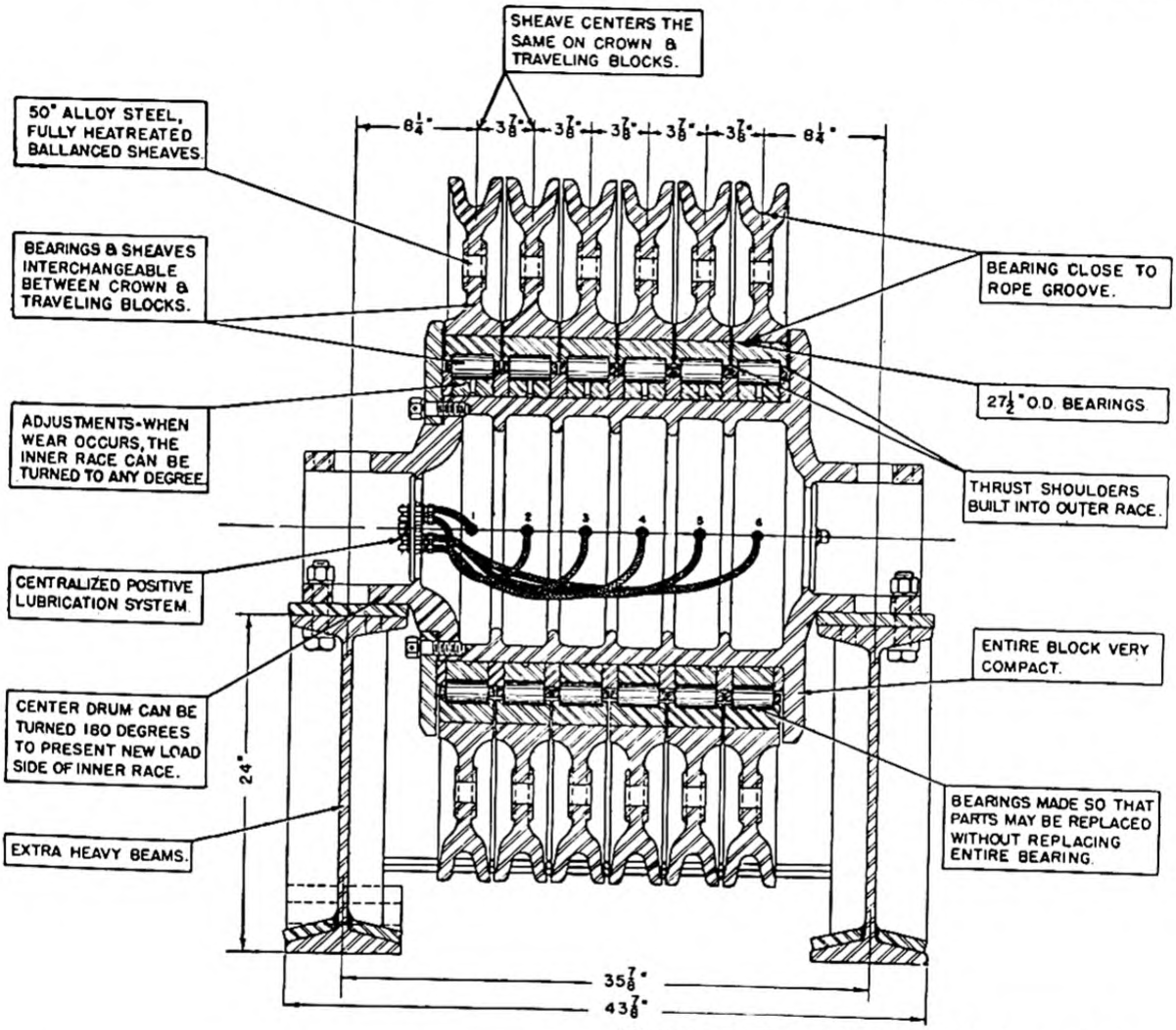
Sprocket 18 on jackshaft 2, controlled by hydraulically actuated clutch 19, drives the rotary table through double sprockets 20, turning on the drum shaft 12 and sprocket 21, keyed to the pinion shaft of the rotary table. With the engine sprocket turning at 200 r.p.m., the four-speed draw works provides a single speed of 241 r.p.m. for the rotary table; but, if equipped with intermediate gear for eight drum speeds, two speeds are possible for the table. With the engine drive shaft turning at 350 r.p.m., these are 222 and 316 r.p.m. The Hydromatic brake 22 may be thrown in or out of service by means of multiple-jaw clutch 23, controlled by lever 24.

The entire mechanism of the draw works is supported as a unit, by welded steel frame 25 and steel skids 26. A nonskid steel grating provides a working platform about the draw works. Catheads 27 are useful in applying power with the aid of a pull rope, in minor operations incidental to drilling and rigging. The cathead nearest the driller's position 28 receives most use and is often of the automatic, water-cooled variety. All controls and gauges are concentrated at the driller's position. This draw works weighs 53,700 lb. and is capable of receiving and transmitting 1,500 hp.

Modern design and construction of heavy-duty draw works of the type described in the foregoing paragraphs provide many improvements not found in models of a decade or two earlier. Flood or "cascade" lubrication is provided by a pump which delivers a continuous supply of oil to all chains and sprockets. Oil drains from them and from the inner surfaces of the oiltight steel housing guards into an oil reservoir connecting with the pump suction through an oil filter. The alemite system of lubrication is used for bearings and other parts not reached by flood lubrication. Roller bearings are used throughout, mounted in alloy-steel hardened raceways. Sprockets are precision-cut by machine methods, and have flame-hardened teeth. Brake rims are of press-forged steel and are water-cooled. The mechanical brakes are of the multiple-leverage type, equipped with a safety equalizer designed to assure uniform tension on each of the two braikes, or to permit one of the two to function in the event that the other fails. Specally constructed, replaceable molded brake blocks are used. During recent years there has been a trend toward use of friction clutches rather than jaw clutches, particularly for the frequently used high-speed drum clutch and table clutch. Clutches may be mechanically, hydraulically or vacuum controlled. No small part of the superior performance and greater strength of the modern draw works is due to the use of materials especially selected for the heavy duty imposed. Electric cast-steel and manganese-steel sprockets, with chrome-nickel steel, forged and heat-treated shafts, cast-steel drums, rolled and forged alloy-steel brake rims and manganese steel clutches and catheads are used in most of the heavier and costlier draw works.

An important phase of draw-works design and construction is found in the brake mechanisms and related features that are provided to promote security in handling heavy drill-pipe loads in deep-drilling practice. Manually controlled mechanical brakes are often scarcely adequate for this purpose and are subject to rapid wear and deterioration in service. More positive action of the hoisting-drum brakes is afforded by hydraulic control mechanisms. The Hydromatic brake, a device often incorporated in the controls of heavy-duty draw works, does not replace the usual mechanical brakes but is used in conjunction with them and relieves them of much of the heavier braking service to which they are otherwise subjected. The Hydromatic brake comprises a rotor which is attached to and rotates with the shaft of the draw works, and a stator which is stationary and is a part of the enclosing housing. Fluid—usually water—circulates between opposing inclined pockets in the rotor and stator, and the fluid resistance to displacement provides the braking effort. Stuffing boxes around the hub of the rotor prevent fluid leakage. The resistance offered by the brake is controlled by a valve which regulates the amount of fluid in circulation, and the energy absorbed is dissipated by heating of the fluid. Water flows in closed circuit between the brake and a small near-by storage tank and cooling tower. Because of inclination of the rotor "pockets," the brake offers little resistance when the drill pipe is lifted, but assumes a large part of the load when it is being lowered. The Hydromatic brake on the right-hand end of the drum shaft in Figs. 82 and 84 may be thrown in or out of use by a clutch. Necessary water piping is, in this case, built into the draw works and the water level is controlled from the driller's position.

The Crown Block.—The crown block, situated at the summit of the derrick, must be capable of supporting the maximum load that may be suspended from the traveling block, as well as the dead load of the traveling block and hook and hoisting cable, and the line pull from the draw works. For deep-well service, a five-, six- or seven-sheave block is used, designed to support safely a load of 350 tons with a safety factor of 2 based on the yield point of the metal. The conventional rotary crown

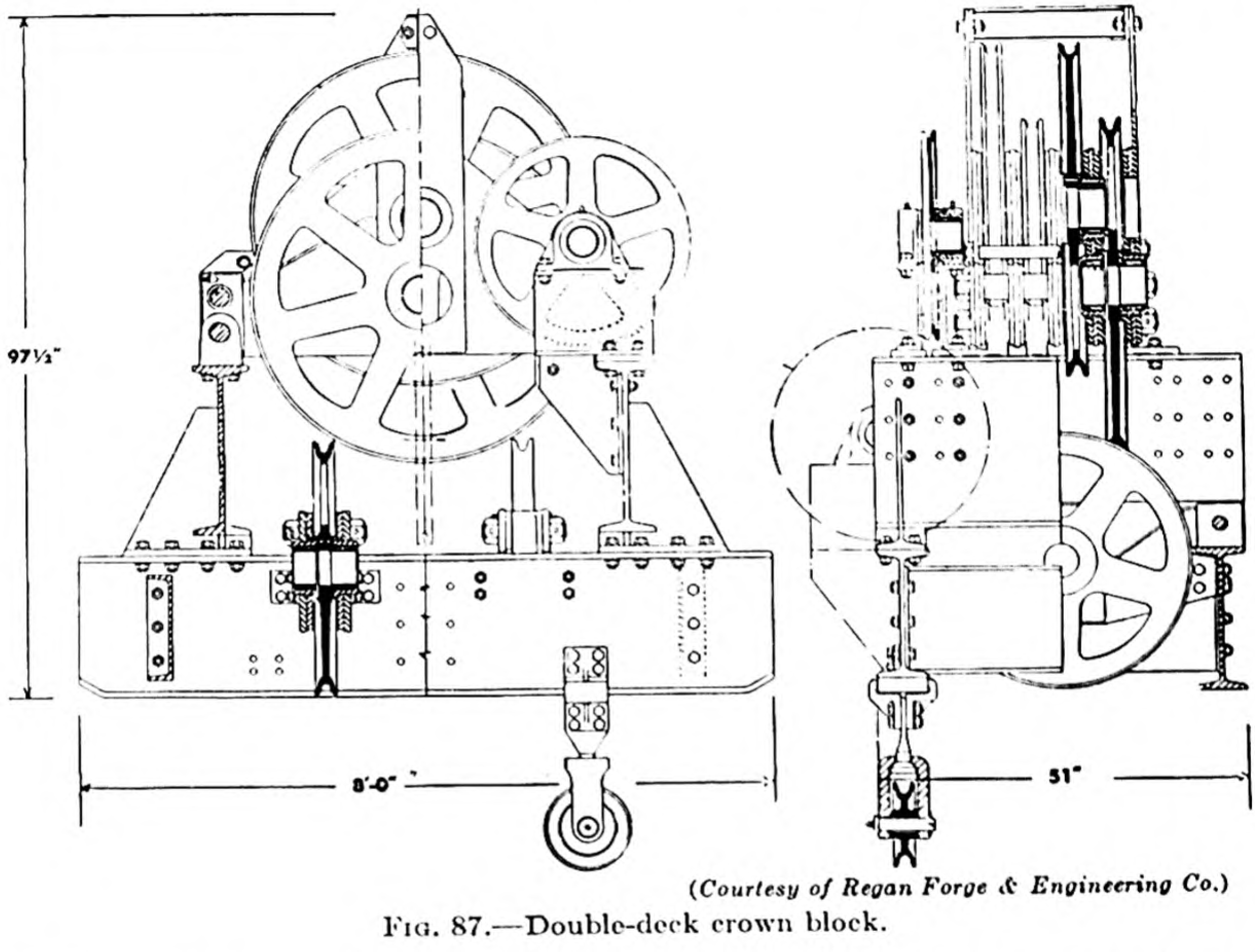


(*Courtesy of Emsco Derrick & Equipment Co.*)
FIG. 86.—Hollow-drum type of crown block.

block may be equipped with from four to seven sheaves, mounted side by side on a single steel shaft or drum supported in a position parallel with the shaft of the hoisting drum of the draw works, on bearings mounted on substantial steel I beams. The latter are fastened together with bolted or welded steel cross members or "spacers" so that they form a rigid steel frame designed to fit into the space provided in the water table of the American Petroleum Institute standard derrick.

Crown-block sheaves range from a diameter of 30 in. in the smaller, lighter blocks to as much as 50 in. in the larger, heavier sizes. As constructed by one manufacturer

the sheaves are of manganese steel for wear resistance, and each is separately mounted on heavy-duty roller bearings which operate in a hardened and ground raceway of chrome-molybdenum steel, shrunk on a heat-treated chrome-vanadium shaft which, in the larger crown blocks, may be as much as 10¼ in. in diameter. Lubrication is an important consideration, grease-gun lubrication being provided in most of the more modern designs. One manufacturer uses a hollow drum 19 in. in diameter instead of a solid shaft, to support the sheaves and their roller bearings (see Fig. 86). This type of construction affords a means of direct alemite lubrication from within the drum to each bearing; also, the bearing is nearer the rope grooves than in ordinary sheaves, thus minimizing the tendency to tilt the supporting frame. The grooves of the sheaves are accurately ground to accommodate a certain size of hoisting cable—usually



(Courtesy of Regan Forge & Engineering Co.)

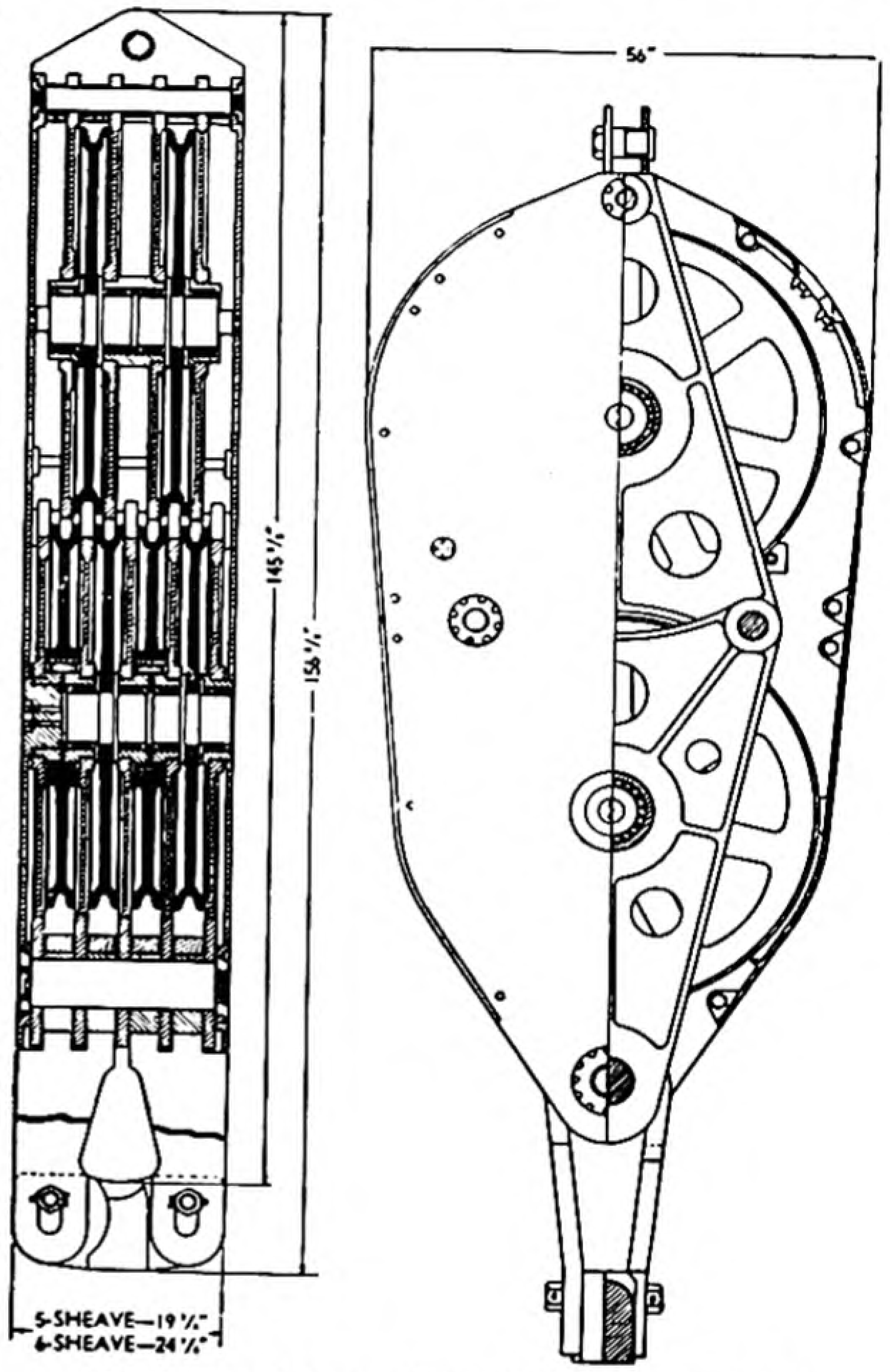
Fig. 87.—Double-deck crown block.

1⅛ in. or 1¼ in.—and are shaped to conform with specifications prescribed by the A.P.I. The frame of the crown block also provides a support for a cat-line sheave, suspended below the base beams and designed to accommodate 1½-in. manila rope.

A radically different arrangement of sheaves is afforded by the double-deck type of crown block (see Fig. 87). In this, the sheaves are supported on shafting at two different levels, those on the lower deck being at right angles to those on the upper deck. In one model, there are two sheaves on the lower deck and either three or four on the upper deck, the latter being somewhat larger in diameter than the former. In addition, a small cat-line sheave may be supported from one of the lower deck beams. Double-deck crown blocks are particularly appropriate for combination rigs of the California type, which require two additional sheaves: a crown sheave for the drilling cable and a sand-line sheave. The double-deck arrangement of the crown-block sheaves permits of better alignment with the hoisting-block sheaves, with less flare or angularity ("fleet angle") in the lines, allowing the hoisting block to be raised to a

higher position in the derrick without destructive side drag and consequent wear on the sheave and hoisting cable.

The Traveling Block and Hook.—The traveling block serves the double function of supporting the drill column and hoisting or lowering drill pipe, and is also used in making up and lowering a column of casing into the well. It may contain from three to six sheaves, depending upon the loads to be handled and the mechanical advantage necessary. A live-sheave block, commonly used, permits of stringing as many as 11 lines between it and the crown block. This provides a mechanical advantage of 10 in favor of the draw-works hoisting drum, on which the free end of the cable is wound. A large, heavy-duty traveling block equipped with five 48-in. sheaves has a rated capacity of 300 tons (computed with an assumed safety factor of 2), is 9 ft. 7 in. long and weighs 11,250 lb. (see Fig. 88).



(*Courtesy of Regan Forge & Engineering Co.*)
FIG. 88.—Six-sheave hoisting block.

The traveling-block sheaves are mounted, each on separate heavy-duty roller bearings, side by side, on a single alloy-steel shaft which may be as much as 10½ in. in diameter. Manganese-steel "spacers," mounted on the supporting shaft, prevent the sheaves from crowding each other. Side plates, fastened together by two alloy-steel pins, provide a support for the center pin or shaft on which the sheaves revolve. Steel guards provide a housing which completely encloses the sheaves, except for slots—one on each side for each sheave, through which the hoisting cable passes. The guards reduce the hazard of workers being caught between the cable and sheaves and prevent the cable from slipping off the sheaves. The lower pin also supports the bottom clevis, which is hinged to permit of convenient engagement with a massive hook or connector that flexibly supports the bail of the swivel or drill pipe or casing elevators (see Fig. 89). A cast-steel bracket supported by the upper pin provides an upper clevis to which the dead line of the hoisting cable may be attached. The exterior of the hoisting block is designed to present a smooth, streamlined exterior surface, so that it will not "hang up" on anything in the derrick with which it may come in contact.

To reduce wear and bending stress in the cable, the sheaves of the hoisting block should be of large diameter. Heavy blocks appropriate for deep-drilling operations

may have sheaves as large as 50 in. in diameter. Like those of the crown block, the sheave grooves are shaped to conform with A.P.I. standards and are designed to receive $1\frac{1}{8}$- or $1\frac{1}{4}$-in. hoisting cable. The size and shaping of sheaves in the hoisting block should, if possible, be the same as those of the sheaves in the crown block, thus restricting angularity in the "lines" of the hoisting cable and reducing side wear on the cable and sheave rims. The width of the traveling block should be no greater than necessary to accommodate the desired number of sheaves, thus permitting the use of short supporting pins (giving greater security) and occupying a minimum of space in the derrick. Stacked "stands" of drill pipe may occupy a large part of the space in the upper part of the derrick, and the traveling block should not be of such proportions as unduly to restrict this space.

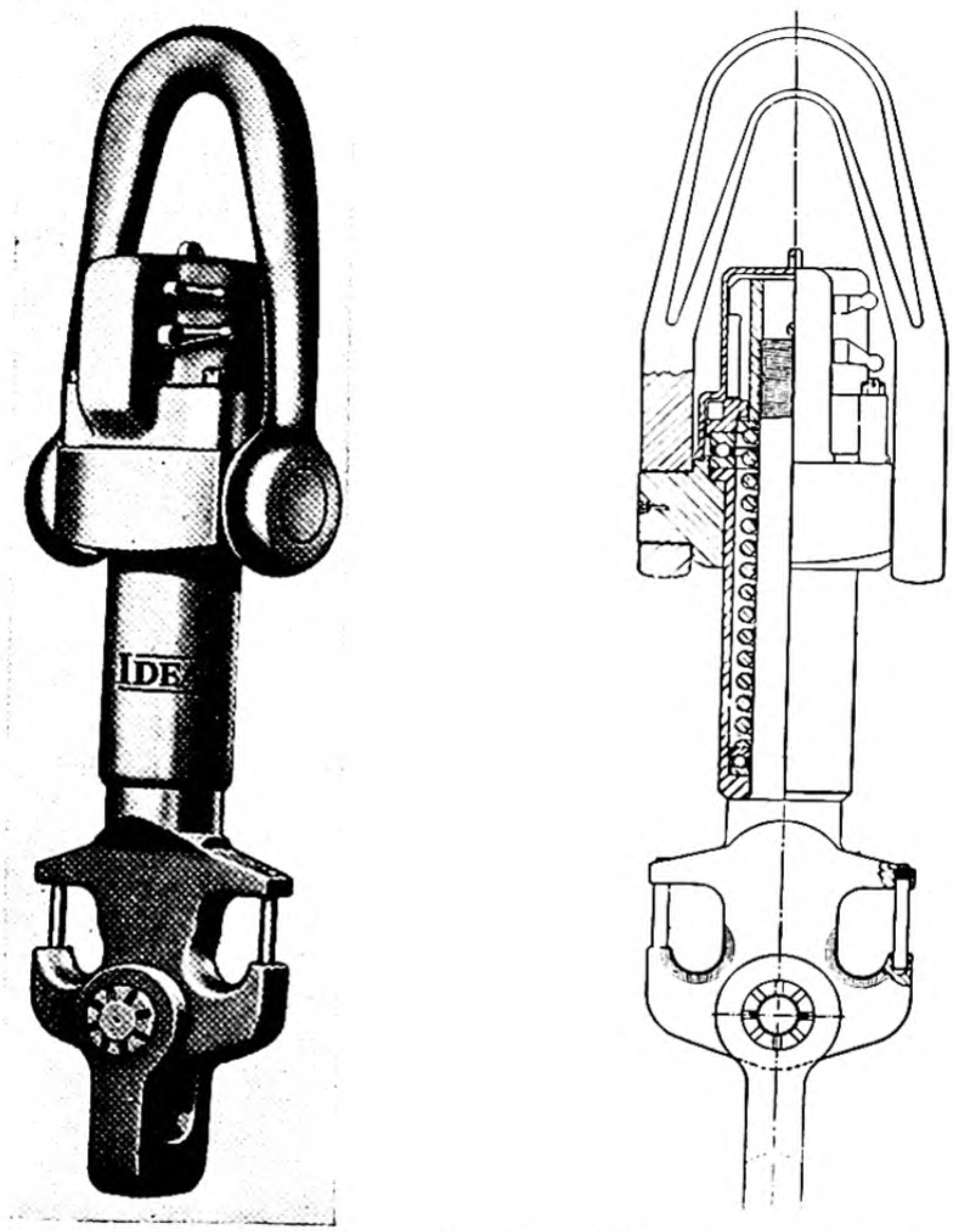
The hook or connector, which provides a flexible connection with and support for the swivel and elevators used in handling drill pipe and casing, is suspended from the lower clevis of the hoisting block; or, in one design, is supported rigidly on steel pins inserted through brackets cast on the lower ends of the side plates of the traveling block. Usually this connecting link in the hoisting gear takes the form of a massive hook supported on a bail and trunnion which incorporates in its construction a powerful coiled spring, designed to relieve the hoisting equipment of sudden shock loads (see Fig. 91). A safety latch prevents the bail of the swivel or the elevator links from slipping off the hook when lines are slackened or when the drill column is subjected to excessive vibration. The hook must be suspended well below the center of gravity of the traveling block; otherwise there is a tendency for the block to turn over when subjected to heavy loads. However, the traveling block and hook should be no longer than necessary; otherwise they unduly restrict the free headroom in the derrick.

The "rotary connector" is a device designed to replace the conventional hook. This provides a massive steel yoke from which each of two elevator links are separately suspended (see Fig. 89). When drilling is in progress, the swivel is supported by the same elevators that are used at other times in manipulating drill pipe, the bail of the swivel being equipped with a special saddle and shank which the elevator clamps engage.

The Hoisting Cable.—The hoisting cable of the rotary drilling rig provides a means of applying the torque of the hoisting drum of the draw works to provide a lifting force on the hook suspended below the traveling block. A steel cable $\frac{7}{8}$ to $1\frac{1}{4}$ in. in diameter and 1,150 to 3,750 ft. long, with one end coiled on the hoisting drum, the hoisting cable passes up through the derrick and over a sheave in the crown block at the summit of the derrick, thence back and forth between sheaves in the hoisting block—suspended in the derrick—and other sheaves in the crown block. The dead end of the line is attached to the upper bail of the hoisting block, to one of the sills or corner of the derrick, to the hoisting drum of a stand-by draw works or to the shaft of a calf wheel. Reeling the "fast" line of the cable on the hoisting drum of the draw works lifts the hoisting block in the derrick and provides a mechanical advantage in lifting the hook load proportional to the number of lines strung between the crown block and the hoisting block.

Hoisting cables are made of six steel-wire strands twisted together about a hemp or steel core. An assemblage of wires twisted together form each strand. Usually

there are 19 wires in each strand, but 6 × 7 and 6 × 8 cables are also occasionally used. In place of the usual hemp core, the six outer strands may be twisted about a smaller steel cable consisting of six strands of seven small wires each. Figure 90 illustrates the construction of several types of steel cables commonly used as rotary lines. Figure 90*C* is made of wires of uniform size and illustrates what is known to the trade as "Warrington" construction. Figure 90*B* illustrates Seale construction,



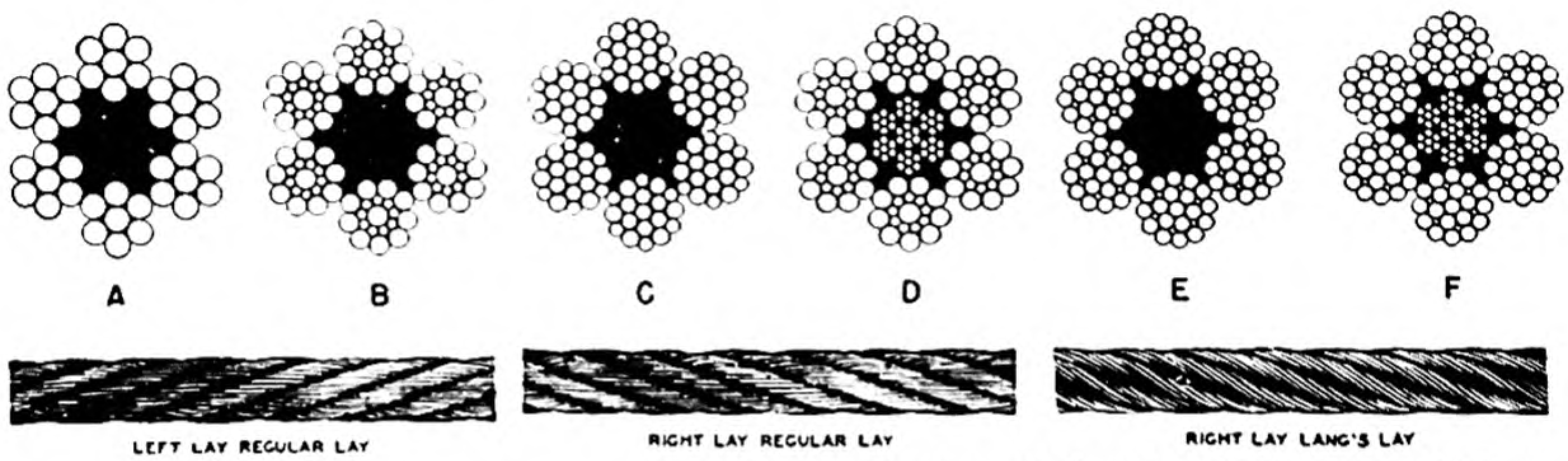
(*Courtesy of National Supply Co.*)

FIG. 89.—Rotary connector for suspending swivel and elevators from hoisting block.

in which each of the six strands consists of a core wire surrounded by nine inner wires of uniform but relatively small size, and outside of these, by nine wires of uniform but relatively larger size (1-9-9). Variations in Seale construction provide strands of more than nine wires in the outer rows, but in each case there are two layers of interlocking wire, the outer layer occupying the valleys between the wires of the inner layer. Seale construction provides a large percentage of the metal in the strand on the outer surface, and therefore has high abrasion resistance. "Filler-wire construction" provides in each strand 18 wires of uniform size, arranged in two concentric circles about a somewhat larger center wire, six wires in the inner circle and twelve in the outer layer. Six smaller "filler wires" are used in the valleys between the two circles, primarily to support the structure of the strand (see Fig. 90*E*). Flattened-strand construction uses strands of triangular instead of round

cross section. Here again, the purpose is to develop a compact cable with a large percentage of the metal on its outer surface.

The wires in the strands may be twisted either to the right or the left. In rotary drilling lines, the wires in the strands are always twisted to the right. If the wires in the strands are twisted in a direction opposite to the direction of the twist of the strands, the cable is "regular lay" (see Fig. 90). If the wires in the strands are twisted in the same direction as the strands, the cable is called "Lang lay." Regular lay is used exclusively in round-strand construction. Lang-lay cables have the advantage of lower fiber stress, better bending qualities, and lower unit radial pressure when the cable is bent around sheaves, and greater wearing surface, but have a tendency to twist the traveling block. Preformed cables are constructed of strands twisted into helical form before they are locked together to form the cable. It is claimed that preformed cables subject wires to less internal stress and give the cable longer life, better spooling properties and less tendency to twist the traveling block.



(Courtesy of American Petroleum Institute.)

FIG. 90.—Types of hoisting cables used for drilling purposes. *A*, 6 × 7 sand line; *B*, 6 × 19 Seale construction; *C*, 6 × 19 Warrington construction; *D*, 6 × 19 Seale construction with wire-rope center; *E*, 6 × 19 filler-wire construction; *F*, 6 × 19 filler-wire construction with wire-rope center.

After many years of study of oil-field requirements, the A.P.I. has adopted standard specifications for steel cable. Three grades of steel are recognized as appropriate for cable construction, with properties as indicated in Table XX. In addition to these materials, cables made of a superior grade of plow steel are available, in which the metal has a tensile strength of from 230,000 to 280,000 lb. per sq. in. The strength of the cable is somewhat less than the aggregate strength of the com-

TABLE XX.—TENSILE STRENGTH OF WIRES USED IN CONSTRUCTION, A.P.I. STANDARD HOISTING CABLES
(Pounds per square inch)

	Grade J	Grade L	Grade N
Individual minimum	210,000	190,000	170,000
Average minimum*	220,000	200,000	180,000
Average maximum*	230,000	215,000	195,000
Individual maximum, outside wires	245,000	235,000	215,000
Individual maximum, inside wires	260,000	250,000	230,000

* Minimum and maximum averages are obtained by dividing the sum of all breaking stresses by the sum of the areas of all wires tested.

ponent wires. Table XXI gives breaking strengths for cables of different sizes and materials as prescribed by the A.P.I.

Grade J steel is otherwise known as plow steel; grade L is the equivalent of extra-strong cast steel; and grade N is sometimes called "cast steel."

TABLE XXI.—ULTIMATE STRENGTHS OF 6 × 19 STANDARD A.P.I. HOISTING CABLES

Nominal diameter of rope, in.	Approximate weight, lb. per ft.	Grade N, lb.	Grade L, lb.	Grade J, lb.	Improved* plow steel
3/8	.23	9,000	10,000	11,000	12,600
7/16	.31	12,000	13,200	14,600	16,800
1/2	.40	15,400	17,000	18,800	21,600
9/16	.51	19,200	21,200	23,400	27,000
5/8	.63	23,600	26,200	28,800	33,200
3/4	.90	33,600	37,400	41,200	41,400
7/8	1.23	45,600	50,800	56,000	64,400
1	1.60	59,000	66,000	73,000	84,000
1 1/8	2.03	74,000	83,000	92,000	106,000
1 1/4	2.50	92,000	102,000	113,000	130,000
1 3/8	3.03	110,000	123,000	136,000	157,000
1 1/2	3.60	130,000	145,000	161,000	185,000

* Not A.P.I. Standard.

The serviceability of a hoisting cable in a rotary drilling rig will depend upon the design and condition of the hoisting gear, its speed of operation and the magnitude of the stresses to which it is subjected. Lubrication of the cable during manufacture and in its subsequent use is also important. The hoisting cable is subjected to severe bending stresses as it passes around sheaves and the hoisting drum. Radial pressure tends to flatten the strands and squeeze out the hemp center and lubricant upon which the cable depends for protection against abrasion and opportunity for movement of wires and strands to adjust for inequalities in stress. Sheaves and hoisting drums should have diameters at least 30 times the rope diameter, and 45 times the rope diameter is recommended for 6 × 19 cables. Larger sheave diameters will increase the rope life. The grooves in the sheaves over which the cable passes must be of hardened metal, such as manganese or other special alloy steel and of

TABLE XXII.—EFFICIENCIES AND STRESS FACTORS IN VARIOUS HOISTING-BLOCK STRING-UPS*

Number of lines, N	4	6	8	10	12
Efficiency, per cent, E†	88.89	82.19	75.99	70.25	64.96
Fast-line pull factor, F‡	.2812	.2027	.1645	.1423	.1283

* After H. F. Simons in *Oil and Gas Jour.*

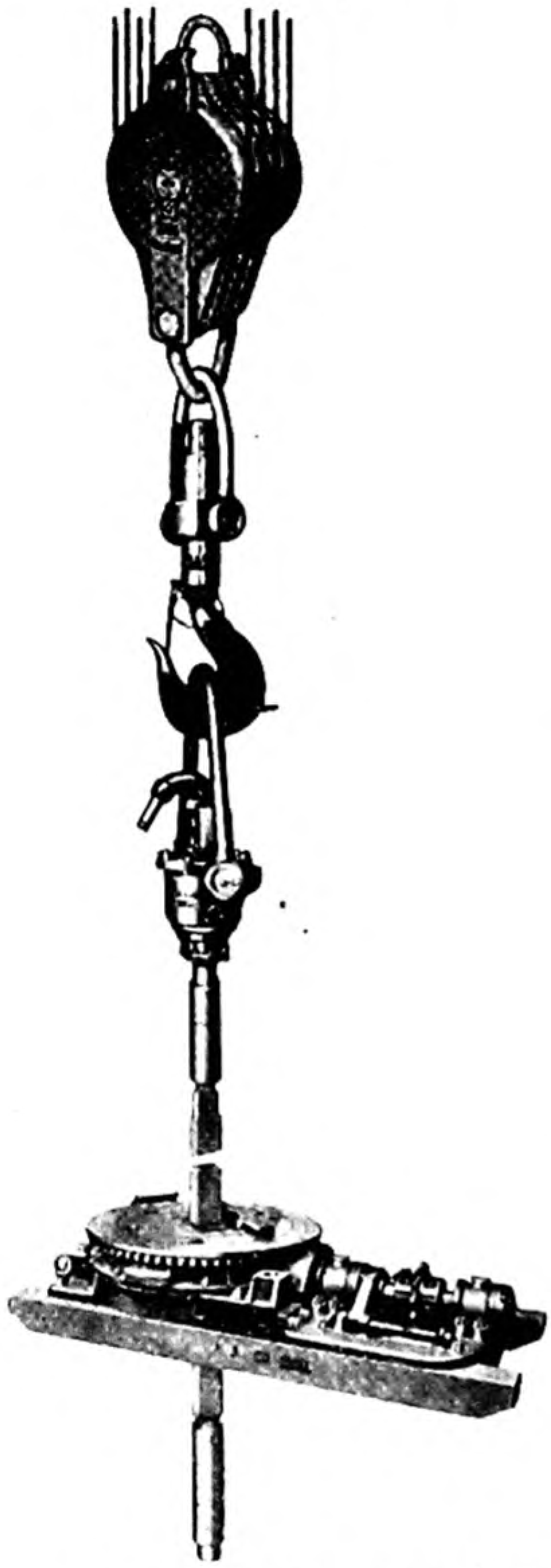
† Per cent efficiency, E, may be computed with the following formula:

$E = \frac{1}{(1.04)^{(N-1)}}$, where N is the number of lines strung through the blocks.

‡ The fast-line pull factor is found by the equation: $F = \frac{1}{N \times E}$.

such contour and depth as will maintain proper clearance and provide 150 deg. of arc support for the cable.[20]

A safety factor of 5 is appropriate in selecting cable for a particular drilling operation and when, as a result of wear or breakage of strands, this is reduced by more than 25 per cent, the cable should be replaced, or the weakened portion cut off and discarded. The fast line, which winds on the hoisting drum, receives more than its share of the wear and stress, and is usually first to fail to meet service requirements. If the cable is longer than necessary and the deadline surplus is wound on a stand-by hoist, the end coiled on the hoisting drum of the service draw works may be cut off occasionally as it becomes worn, and new, unused cable uncoiled from the stand-by hoist to take its place. In this way, one cable may serve for the drilling of a deep well if care is taken in its installation and use and if it is kept well lubricated.



(Courtesy of National Supply Co.)
FIG. 91. Hoisting block, hook, swivel, grief stem and rotary table in working position.

The load on each of the several lines reeved between the traveling block and the crown block is not the average obtained by dividing the total hook load by the number of lines but, owing to friction and other factors, it will vary with the position of the rope in the string. Also, the mechanical efficiency will not be directly proportional to the number of lines. Table XXII gives efficiency and stress factors that may be applied to determine the mechanical efficiency or the stress in the fast line for any of the commonly used "string-ups." Figure 161 illustrates a common method of stringing the hoisting cable between the several sheaves of the crown block and the hoisting block.[23]

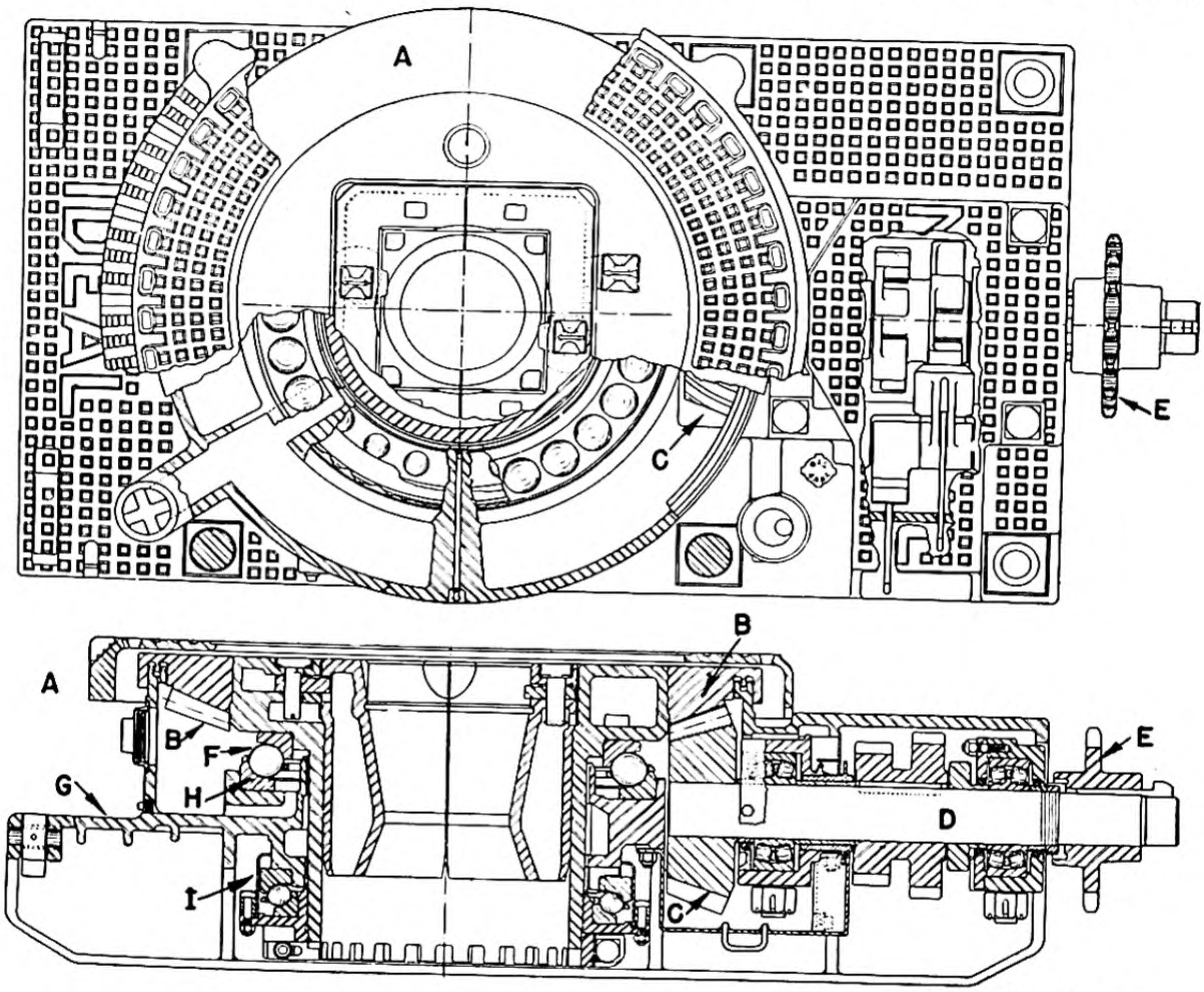
The Rotating Elements

The rotating elements of the rotary drilling rig are (1) the rotary table; (2) the swivel; and (3) the drill column, which includes the grief stem or "kelly," the rotary drill pipe, its couplings, tool joints and protectors, the drill collar and drilling bit (see Fig. 91). Each of these elements has its particular function; each involves special problems of selection and design.

The Rotary Table.—The rotary table has two principal functions to perform: (1) to grip and rotate the kelly when screwed to the top of the column of drill pipe, yet permitting the kelly to slip vertically through the table; (2) to support the column of drill pipe in the well when suspended in a stationary position by slips set in the table bushings. It

may also be used to support lighter "strings" of casing in the well and may assist in making up and breaking out screw joints in inserting or withdrawing casing or drill pipe into or from the well.

The rotary table consists of a heavy casting, A, 4 to 5 ft. in diameter, with a circular, flat top and with bevel-ring gearing B secured rigidly to a shoulder on the under side (see Fig. 92). Meshing with this bevel-ring gear, is a drive pinion C mounted on a



(*Courtesy of National Supply Co.*)
FIG. 92.—Heavy-duty rotary table. Above: plan view. Below: vertical section.

pinion shaft D to which is also keyed a sprocket E. This sprocket receives power by a chain drive from a sprocket on one of the shafts of the draw works, or from the drive sprocket of an engine mounted on or under the derrick floor. The table revolves on ball or tapered-cone bearings F supported by the metal base G. The grooves in the table and table base, in which the bearings are placed, are fitted with renewable flanged race plates H of alloy steel, which provide a housing for the bearings and prevent wear on the heavier castings. The support for the pinion shaft D is cast integrally with the table base and is fitted with roller bearings. To resist upthrust and prevent the table from being lifted or tilted in its supports by the pinion, when under strain, a hold-down ring I is built into the table base. This ring is also equipped with ball bearings to reduce friction. Substantial steel housing guards completely enclose the moving parts below the table top. A nonskid tread is cast into the upper surface of the table housing to minimize the danger of slipping when floor men of the drilling

crew brace their feet against the table in making up or breaking out drill-pipe or casing joints.

Through the center of the table, an opening is provided for passage of drill pipe and casing. This opening is usually square on top and conical below, and is fitted with a split master bushing which, in turn, may support secondary bushings of various forms for driving the kelly or slips in supporting drill pipe or casing. Rotary tables are rated by the diameter of the circular opening through the table and vary from 12 to 27½ in. The size of this opening is also a measure of the maximum diameter of drilling bit that can be passed through the table and hence determines the maximum diameter of hole that can be drilled. In some models however, slot-shaped extensions of the table opening permit of passing a fishtail bit of slightly larger width than the diameter of the table opening. A 20½-in. table is large enough to pass casing as large as 18⅝ in. and weighs about 9,700 lb. A 27½-in. table will pass the largest size of casing likely to be used in American field practice and weighs 11,400 lb.

Modern rotary machines feature superior lubrication systems. The main bearings and gears are flood-lubricated, rotation of the table maintaining circulation of the 12 to 14 gal. of oil stored in the oil reservoir. The hold-down and pinion shaft bearings are equipped for alemite lubrication. Double tongue-and-groove joints in the steel housing guards retain the lubricant in the main bearing raceway and exclude moisture, mud and dirt.

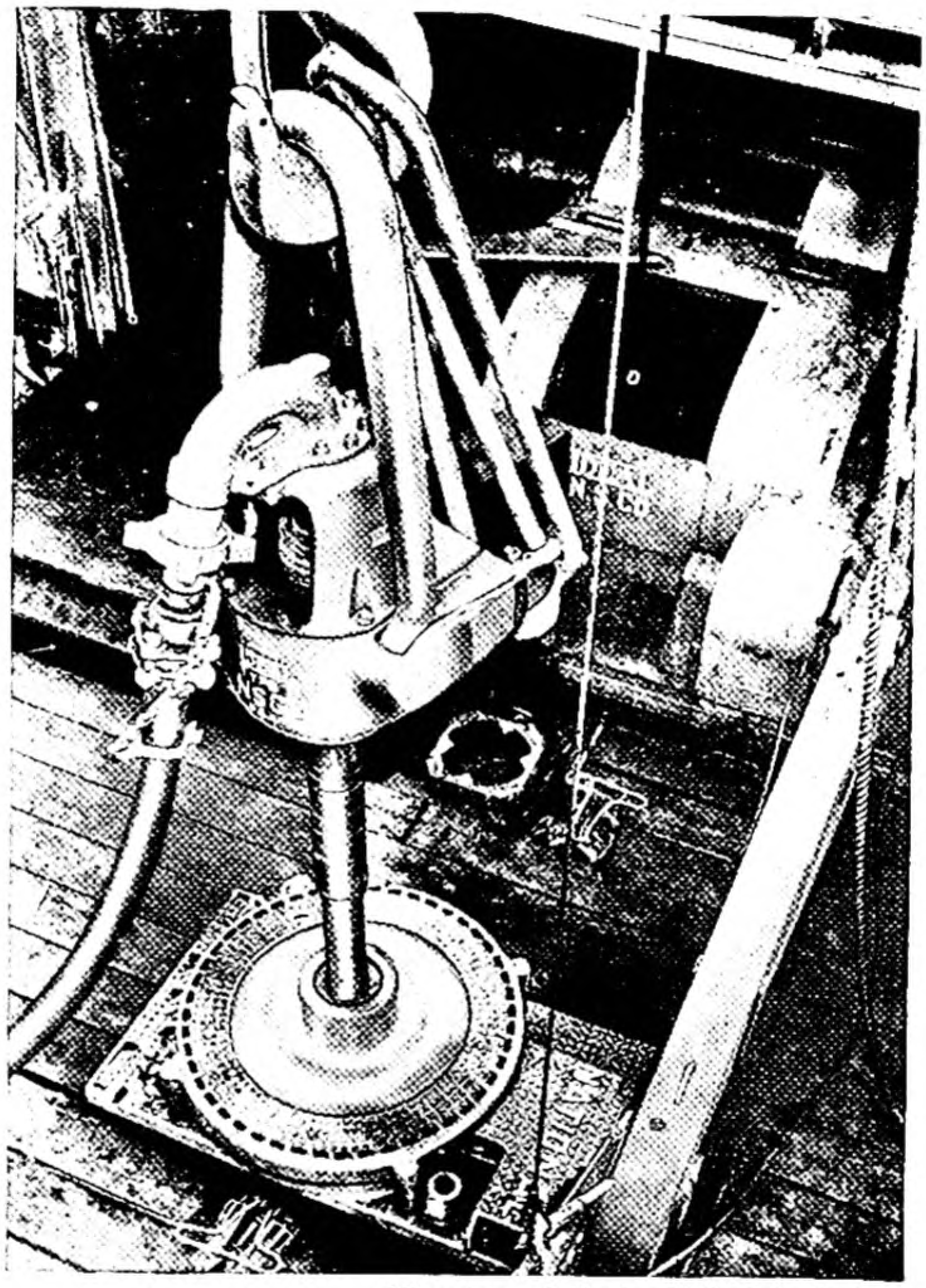
The materials employed are carefully selected to give the maximum of strength and long, trouble-free operation. The rotating element of the machine is an alloy-steel casting. The base is a steel casting, carefully designed to withstand all drilling strains and shocks. The pinion shaft is made from heat-treated forged alloy steel. The square opening in the table top is machined to size and the driving faces are flame-hardened to minimize wear. Spiral bevel gears are preferred to straight bevel gears. Owing to continuous overlapping tooth engagement, spiral gears provide smoother and quieter operation with a minimum of impact stress and vibration. Greater strength and reduced wear are also characteristic of spiral gears. The rotary machine must be designed to support the full weight of the column of drill pipe in the well with rotational speeds as high as 400 r.p.m. To attain this, gear ratios range as high as 4 to 1.

The table is used to support the drill pipe or casing in the well, while tongs are applied to make up or break out the threaded joints. For this purpose, specially designed slips are inserted in the table bushing. To prevent the table and lower portion of the pipe column from turning when the tongs are applied, the pinion shaft is equipped with a lock ring and pawl that can be readily shifted into the locked position when necessary. So-called "make-and-break" rotary tables are also provided with special facilities for coupling and uncoupling drill pipe and casing. A gripping device that may be fitted into the table base supports the pipe below the collar or tool joint to be worked on. The table is then free to turn without the pipe. A post, supported in a vertical position in a hole in the table top, bears against the handle of the pipe tongs, attached to the pipe above the joint; and thus the joint may be made up or broken out by rotating the table with the power.

The conventional method of operating the rotary machine is by chain belt from a sprocket on one shaft of the draw works to the drive sprocket on the pinion shaft of the table, but other methods of applying power to drive the table are possible. With a two-shaft draw works, the drive sprocket is on the line shaft and the long chain belt angles downward across half the width of the derrick floor. Because of its exposed location, its high operating speed, the variable and often extreme strain imposed upon it and its susceptibility to breakage, this chain is a menace to the men at work on the derrick floor unless it is protected by steel guards or housing. Even then, it is a

formidable obstruction that restricts the passage about the table. With a three-shaft draw works, the chain drive to the table pinion-shaft sprocket is from sprockets on the jackshaft and drum shaft, and is more nearly horizontal and nearer the derrick floor. However, it still must be protected with steel guards that are a serious obstruction across half of the derrick floor (see Fig. 93).

Several methods of avoiding the difficulties occasioned by a long chain drive across the derrick floor to the rotary table have been devised. One of these provides a shaft



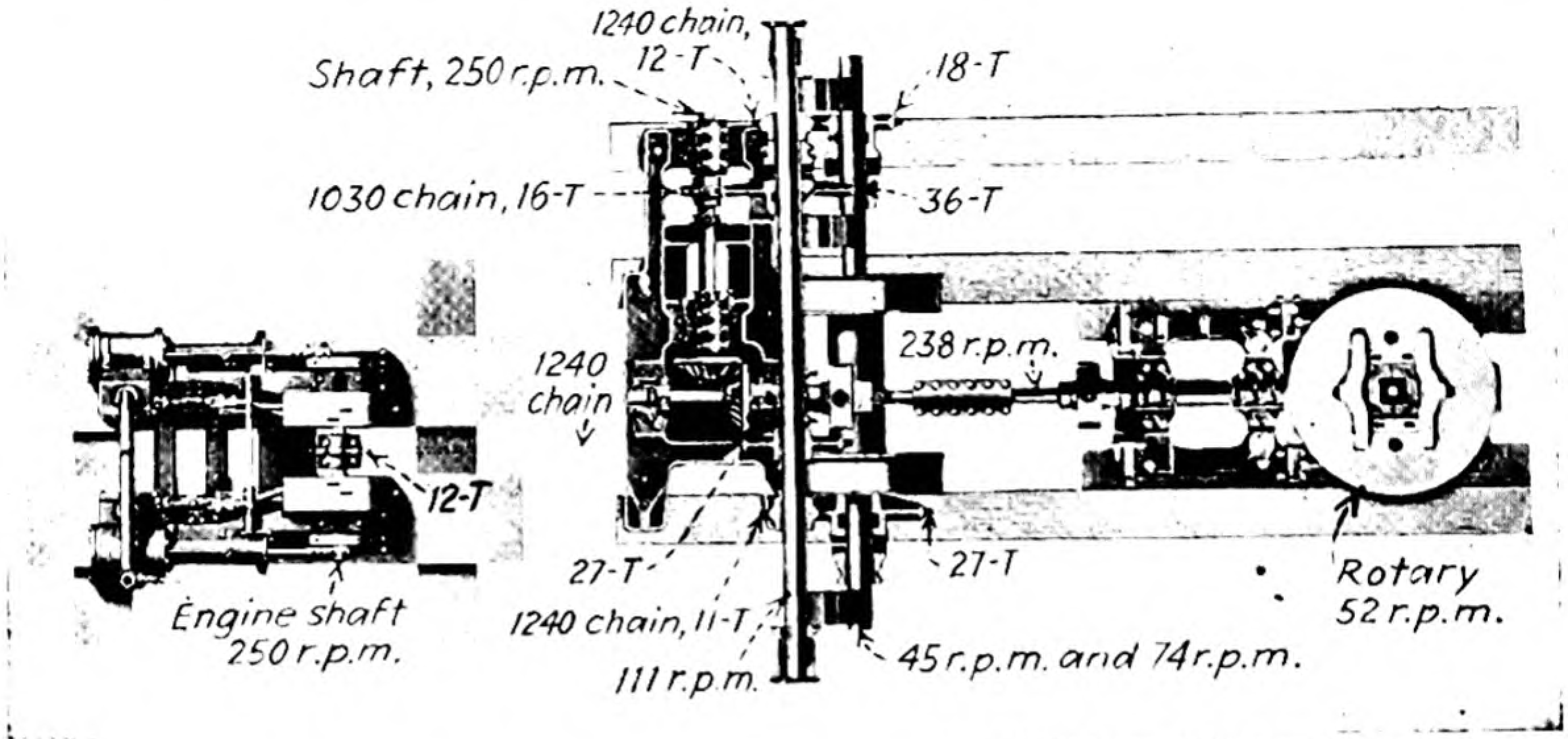
(*Courtesy of National Supply Co.*)

FIG. 93.—View looking down on derrick floor, showing draw works, rotary table, swivel, hook and hose.

drive for the rotary machine from a gear base behind the draw works (see Fig. 94). In this, the pinion shaft of the table is placed at right angles to its usual position, and extends across the derrick floor under the hoisting drum to the gear base between the draw works and the engine. A low housing covers the shaft where it crosses the derrick floor. The gear base contains two beveled gear pinions which permit of revolving the table drive shaft by a short pinion shaft, mounted parallel with the line shaft of the draw works. A pair of sprockets on the two latter shafts and a chain belt provide the necessary power connection. Once popular, the shaft-driven table is now little used.

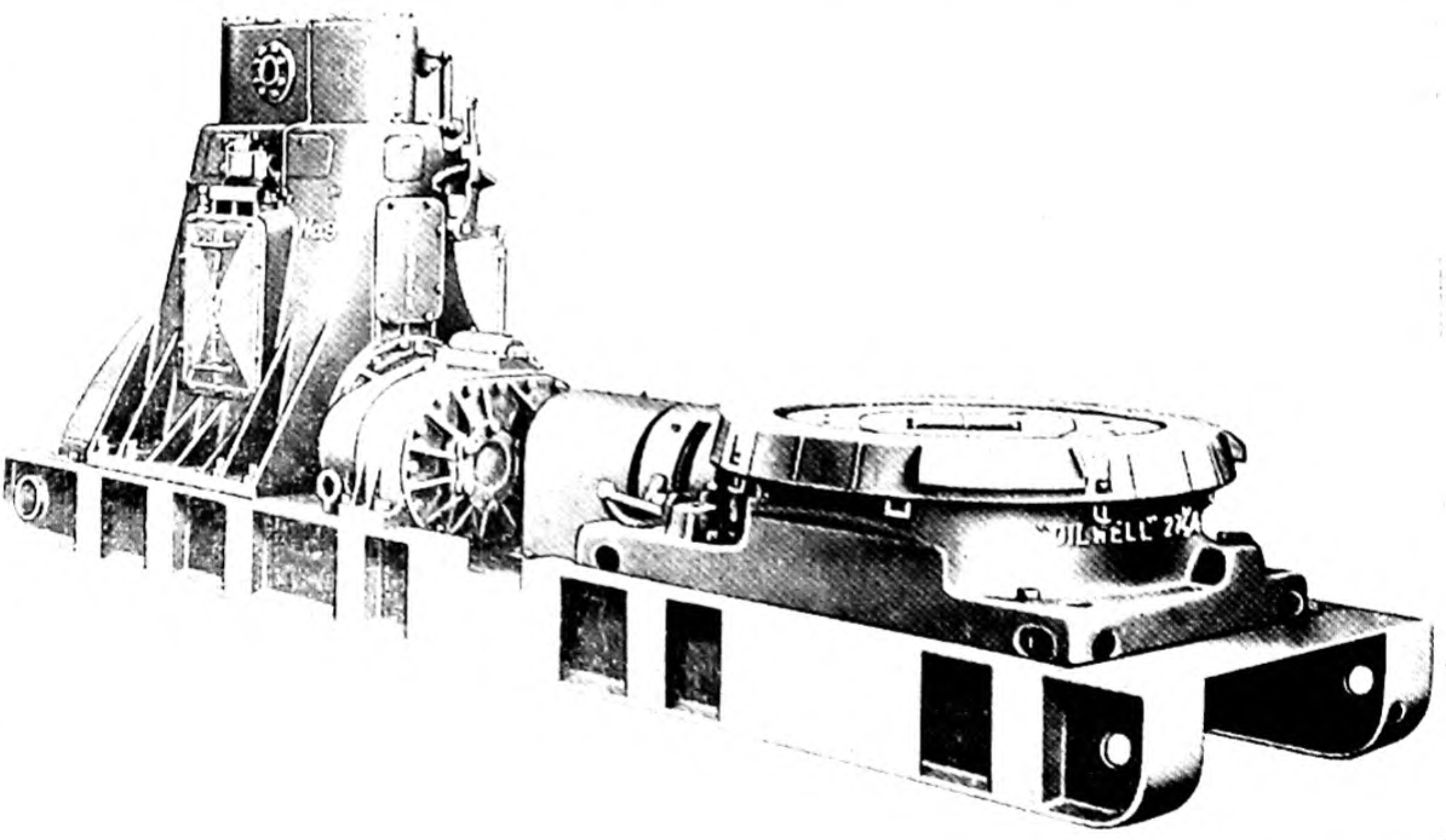
The recent trend in deep rotary drilling has been toward the use of a separate engine to drive the rotary table, apart from that provided to drive the draw works.

Such an engine may be smaller than that required for driving the draw works and it may be placed on the derrick floor near the rotary table, with a short chain drive or direct shaft drive to the table pinion; or it may be placed under the derrick floor with



(*Courtesy of National Supply Co.*)

FIG. 94.—Plan view of shaft-driven rotary equipment showing arrangement of twin-cylinder steam engine, gear unit, draw works and rotary table.



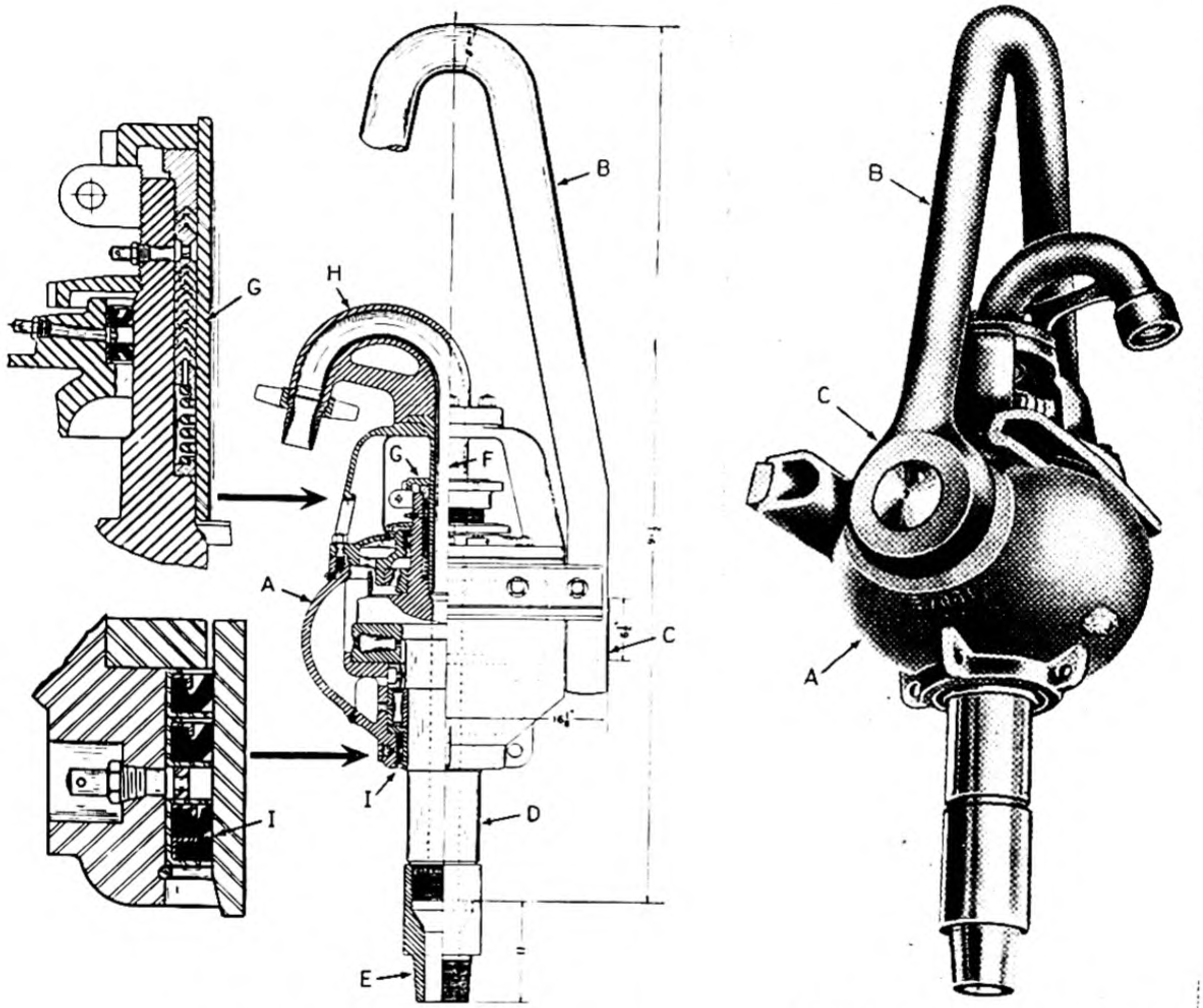
(*Courtesy of Oil Well Supply Co.*)

FIG. 95.—Rotary table with integrally mounted vertical two-cylinder steam engine and speed-control gear.

a comparatively short, inclined chain drive up through a hole in the floor to the table sprocket. The latter arrangement has the great advantage that power-transmission mechanism does not obstruct the working space around the table on the derrick floor, and the accident risk is much reduced. If placed on the derrick floor, a twin-cylinder vertical type of engine, which occupies less floor space than a horizontal engine, may

conveniently be used (see Fig. 95). A separate engine drive for the rotary table is economical from the standpoint of power consumption, for it can operate most of the time at full-load efficiency and does not have to transmit its motion through power-consuming intermediate mechanisms. It also saves wear and tear on the draw works and its larger and more expensive engine.

The Swivel.—The swivel provides a means of forcing drilling fluid from stationary pump connections into the rotating drill column while



(*Courtesy of Lucey Export Corp.*)

FIG. 96.—Type of swivel designed for heavy-duty rotary drilling.

the latter is suspended in the well. Being a part of the mechanism by which the drill column is suspended from the derrick crown block, the swivel must be of massive construction so that it is capable of supporting the full weight of the drill column—perhaps aggregating as much as 150 tons—while it is rotating at speeds that may range up to 350 r.p.m., or even more in exceptional cases (see Fig. 93).

The swivel comprises several parts, all of which are contained within or attached to a heavy, fluidtight body or housing A, supported by a massive bail B and trunnions C (see Fig. 96). Roller bearings in the body of the swivel support the sleeve or rotating

element D, which is attached at its lower end by a box-and-pin joint E to the upper end of the grief stem or kelly. In some designs, smaller ball bearings are so mounted in the body of the swivel that they hold the sleeve on the main bearings against any upthrust that may occur in the course of drilling. Projecting down into the upper end of the rotating sleeve, the "wash pipe" F is supported in the upper portion of the body by a packing gland G, secure against high fluid pressure. The wash pipe connects at its upper end with the gooseneck H, which is threaded for connection with a flexible hose designed to carry high-pressure drilling fluid from the pump manifold. The slope of the gooseneck should approximate the natural slope of the hose suspended from it. The bearings are immersed in an oil reservoir confined within the steel housing, containing in the larger, heavier swivels as much as 50 gal. of lubricating oil. Mud and oil seals I confine the fluids so that there is no leakage of drilling fluid into the bearings, or of lubricating oil into the drilling fluid channels.

The larger swivels, designed for deep drilling, are capable of supporting loads as great as 250 tons and weigh as much as 6,250 lb. Lengths range to nearly 10 ft. In order to accommodate the volume of fluid required, without undue pressure loss, the fluid-carrying tubes should be of large diameter—usually 3 or 4 in. Heat developed by long-continued motion of the rotating elements is transmitted to the housing by the lubricant and cooling is by radiation. A "breather tube" connecting with the top of the oil reservoir permits escape of oil vapors that may form as a result of overheating.

The Drill Column.—The drill column has several important functions to perform. It must provide a continuous, elastic connection between the swivel, when suspended in the derrick, to its lower end which supports the drilling bit on the bottom of the well. It must be capable of transmitting to the drill the rotating motion and torque imposed by the rotary table, without excessive frictional and elastic losses. It must also provide a closed conduit for transmission of the drilling fluid from the swivel at its upper end to the "eyes" of the bit at its lower end. Distortion during rotation brings the elements of the drill column into contact with the walls of the well at many points and, as a result of the rolling pressure thus developed, the drill pipe aids in forming a smooth clay sheath on the walls of the well. The drill column functions as a torque tube that must be rugged and strong to withstand the severe stresses and constant fatigue and abrasion to which it is subjected in service.

The drill column comprises an assemblage of cylindrical steel tubes connected, end to end, by collars or tool joints. Tool joints are conical threaded joints especially designed to facilitate coupling and uncoupling of the drill pipe into stands of such length as will permit "racking" the pipe in a setback in the derrick. Connections at intermediate joints between tool joints are made with pipe collars. The length of the stands that may be racked in the derrick, which determines the interval between tool joints, will depend upon the height of the derrick. With four-joint stands of range 1 drill pipe, tool joints are about 90 ft. apart. At intervals along the drill column, supported on its outer surface, rubber drill-pipe "protectors" may be mounted to reduce wear incidental

to rubbing of the drill pipe against the wall of the well, or against the inner surface of casing through which it must often operate.

As a result of many years of study of the problem of developing the most dependable drill pipe for rotary drilling, a committee of the A.P.I. has adopted standard specifications that govern the manufacture of most drill pipe used by the petroleum industry.[13] A.P.I. drill pipe is of seamless construction, made of grade C, D or E steel, having the properties indicated in Table XXIII. It is available in the sizes shown in Table XXIV, and in two types: internal upset and external upset. A.P.I. specifications provide that drill pipe shall be available in three ranges of length: range 1, 18 to 22 ft.; range 2, 27 to 30 ft.; and range 3, 38 ft. or more.

In selecting drill pipe of appropriate size and weight for a particular drilling operation, consideration is given to the diameter and depth of the well to be drilled. Small-diameter holes and rapid rotation of the rotary table require use of the smaller sizes of drill pipe. In California practice, the 6⅝-in. size is used only in large-diameter holes of comparatively shallow depth; 5⁹⁄₁₆-in. pipe may be used in drilling 11-in. holes to depths as great as 10,000 ft. and with table speeds as high as 400 r.p.m. For high rotational speeds at greater depth, 4½-in. or smaller pipe is used. For drilling out cement plugs and drilling into producing formations, 3½-in. drill pipe is often used.

TABLE XXIII.—PHYSICAL PROPERTIES OF STEEL USED IN MANUFACTURE OF A.P.I. DRILL PIPE

	A.P.I. grade symbols		
	C	D	E
Yield strength, lb. per sq. in. (minimum)	45,000	55,000	75,000
Tensile strength, lb. per sq. in. (minimum)	75,000	95,000	100,000
Percentage elongation, 2 in. (minimum)	20	18	18

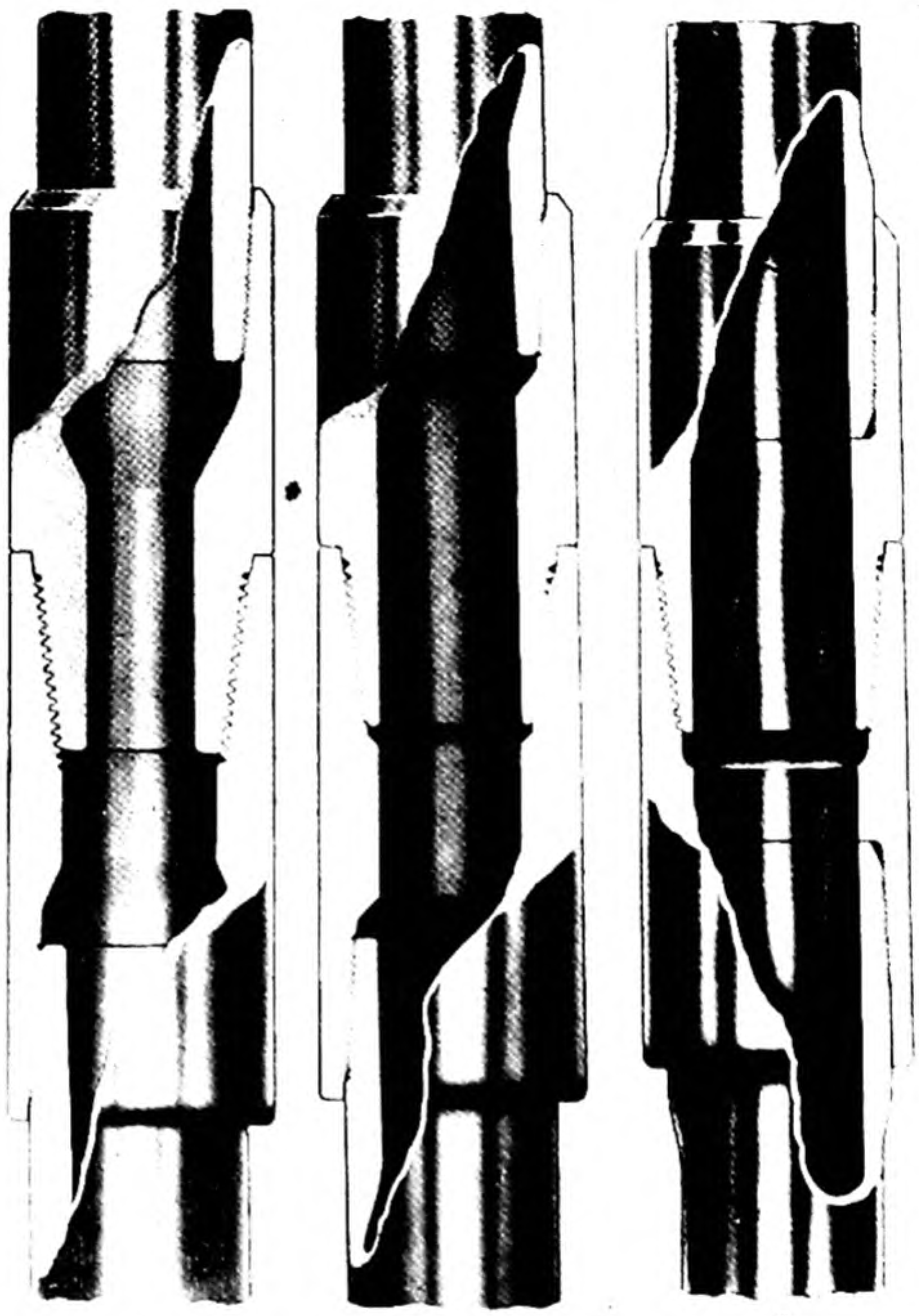
TABLE XXIV.—WEIGHTS AND DIAMETERS OF A.P.I. STANDARD DRILL PIPE

Outside Diameter, In.	Nominal Weight per Foot, Including Threads and Couplings, Lb.
2⅜	6.65
2⅞	10.40
3½	13.30
3½	15.50
4*	14.00
4*	15.70
4½	16.60
5⁹⁄₁₆	22.20
5⁹⁄₁₆	25.25
6⅝	25.20

* The 4-in. sizes are not standard.

The drill pipe must be sufficiently large and heavy to afford adequate strength, and yet must leave sufficient space between it and the walls of the well for flow of the drilling fluid and formation cuttings back to the surface. In this connection, the operator must seek a compromise between flow resistance inside and outside of the drill column. With perhaps 700 to 800 gal. per min. of drilling fluid—or at times, even as much as 1,000 gal.—flowing down through the drill pipe, flow velocities as high as

17 ft. per sec. are not uncommon. Obviously, the inside pipe diameter must be as large as possible if we hope to keep flow resistance within reasonable bounds. Flow velocities through the annular space outside the drill pipe are much lower—perhaps 3.5 to 5 ft. per sec.—depending upon the diameter of the hole, the size of the drill pipe and volume of fluid in motion, but flow outside of the drill pipe necessarily consumes much of the pressure imposed on the circulating fluid by the slush pumps. Friction of



(Courtesy of Reed Roller Bit Co.)

FIG. 97. Types of tool joints used on rotary drill pipe. *A*, A.P.I. regular tool joint on internal upset drill pipe; *B*, A.P.I. full-hole tool joint on internal upset drill pipe; *C*, super shrink-grip internal-flush tool joint on special upset drill pipe.

fluid moving along the rough walls of the well, and turbulence induced in flowing around projecting collars, tool joints and rubber protectors on the outside of the drill column are also likely causes of pressure loss. The drill-pipe couplings, as prescribed by A.P.I. standards, are of special design, with recessed threads and heavier-than-standard construction in order that they may withstand the severe strains imposed upon them. They are cut with eight 60-deg. V-shaped threads per inch—a deep thread in order to avoid stripping under severe strain.

Tool Joints. Tool joints used on rotary drill pipe are of a variety of different styles and types but only three have thus far been recognized as

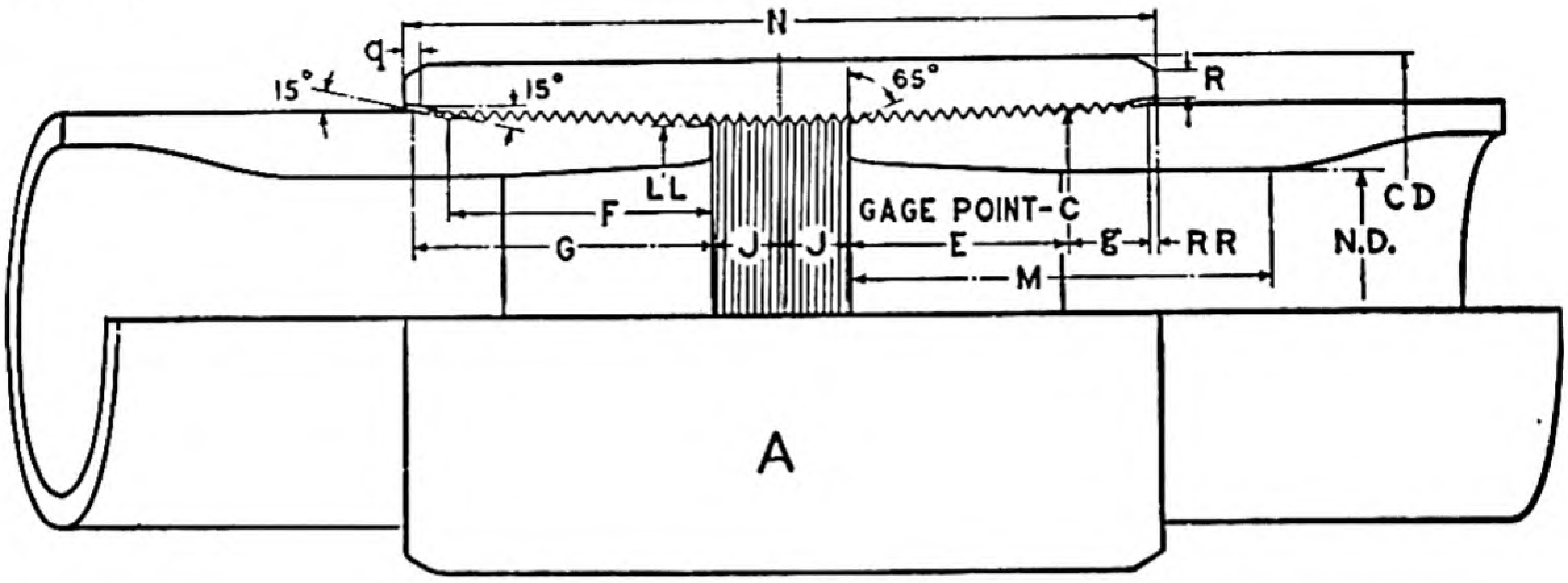
standard by the A.P.I. These are (1) "regular," (2) "full-hole" and (3) "internal-flush" tool joints (see Fig. 97). All three types are equipped with pipe threads at each end to screw on to the end of a section of drill pipe, and constructed in two halves that are coupled together by a box-and-pin type of conical threaded joint. In the regular pattern, the diameter of the cylindrical hole through the joint is somewhat smaller than the inside diameter of the drill pipe, presenting a constriction in the flow channel at each tool joint that occasions considerable turbulence and pressure loss in the circulating fluid. The opening through the full-hole type of tool joint is equivalent in size to that through the upset ends of internal-upset drill pipe, still somewhat smaller than the full diameter of the drill pipe at mid-section, and thus presenting a minor constriction in the flow channel. Internal-flush tool joints are intended for use on externally upset drill pipe and are so designed that the opening through the joint is everywhere equal in size to that through the drill pipe itself.

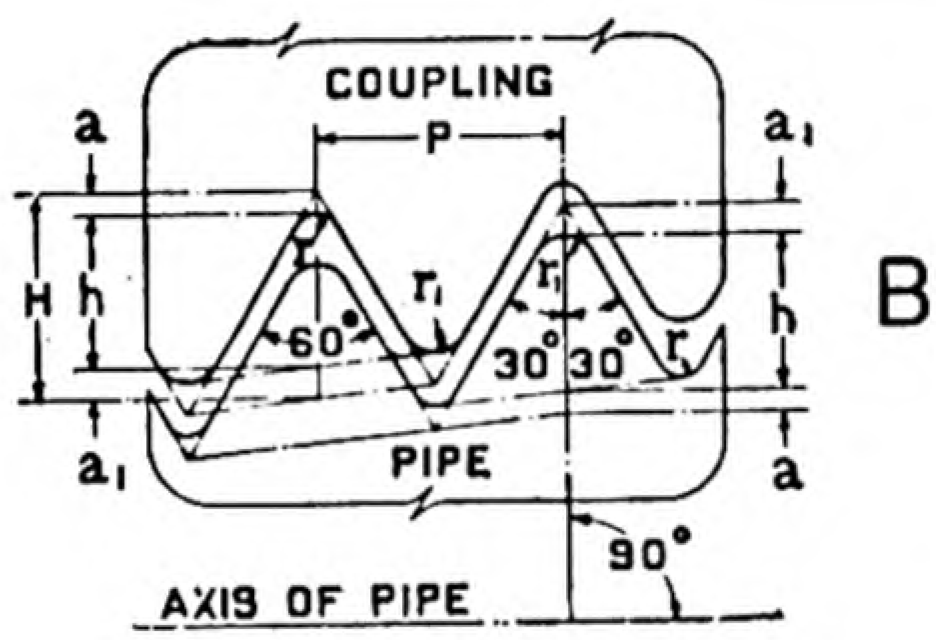
Tool joints are usually made of alloy steel, carefully selected and heat-treated to assure the best possible combination of strength, hardness and fatigue resistance, to withstand the very severe duty imposed. To reduce scouring and turbulence and pressure loss in the ascending drilling fluid, the exterior surfaces of tool joints are preferably streamlined. That is, projecting edges are beveled or rounded and external diameters are maintained as small as may be consistent with strength and tolerance for abrasive wear. Portions likely to suffer by sand-scouring—particularly the exposed ends—may be protected by hard-facing fusion metals. The conical box-and-pin joints are customarily threaded with 60-deg. V threads, modified to adapt to the form of the surface upon which they are cut, and with rounded crests and troughs (see Fig. 97). The form and dimensions of tool joints and threads of this type have been fully specified by A.P.I. standards. However, some manufacturers employ threads of special form, designed to facilitate rapid coupling and uncoupling, or to increase security of the joint. For example, square threads, modified square threads or Acme threads are sometimes used.

Although A.P.I. standards prescribe that tool joints shall be attached to the drill pipe by threaded joints, other methods are often employed. A common method involves reinforcing the joint by welding the end of the tool joint to the drill pipe by means of a "bead" of fusion metal, formed in the recess between them, or by means of a narrow ring of metal welded to the drill pipe at the base of the threads and to the end of the tool joint after it is "bucked up" securely to lock the parts firmly together. "Integral" tool joints are also available. Here, half of the tool joint is formed directly upon the externally upset ends of the drill pipe itself, so that it is a permanent part of the drill pipe. This, of course, removes the necessity for threaded connections between the drill pipe and tool joint and, if abnormalities in fiber stress can be avoided in the forging and heat-treatment process, a stronger and more secure joint should result. However, tool joints are subjected to considerable wear, and repair and replacement become more difficult when the joint is integrally attached to the pipe.

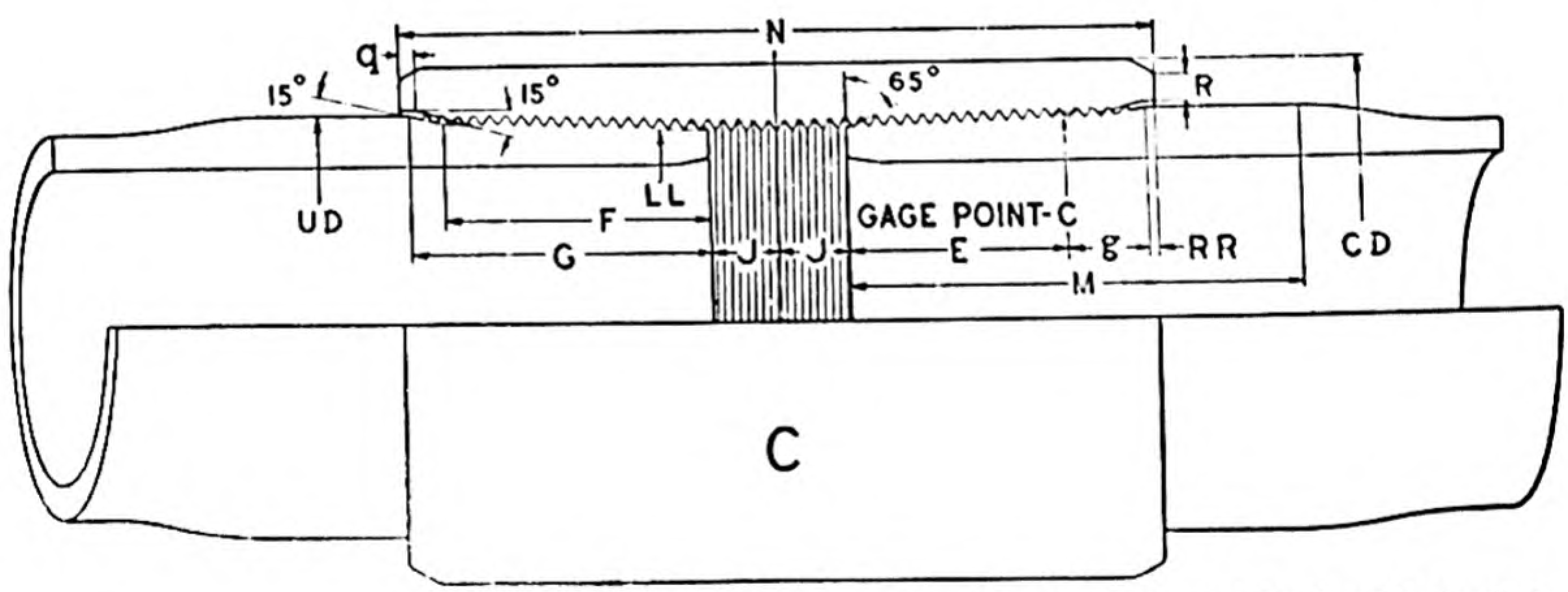
Integrally formed tool joints may provide a "box" on the end of one joint of drill pipe and a "pin" on the end of the connecting joint; or a box may be formed on the end of each joint and the connection made by a double-pin "sub"; or the drill-pipe joints may have integrally formed pins and be connected by a double-box sub.

To prevent tool joints from unscrewing in service, they may be so designed that they provide a steeply tapered machine-shouldered fit beyond the threaded section; or, for added security, the "shrink-grip" type of joint may be used, in which these shouldered areas are shrunk one on the other by heating the outer joint as it is made up.





THREAD DIMENSIONS - INCHES	
THREAD ELEMENT	NUMBER PER INCH
	8
	P = .125
H = .866 P	.1082
h = .626 P - .007	.0712
a = r = .120 P + .002	.0170
$a_1 = r_1$ = .120 P + .005	.0200
TAPER 3/4 PER FOOT	

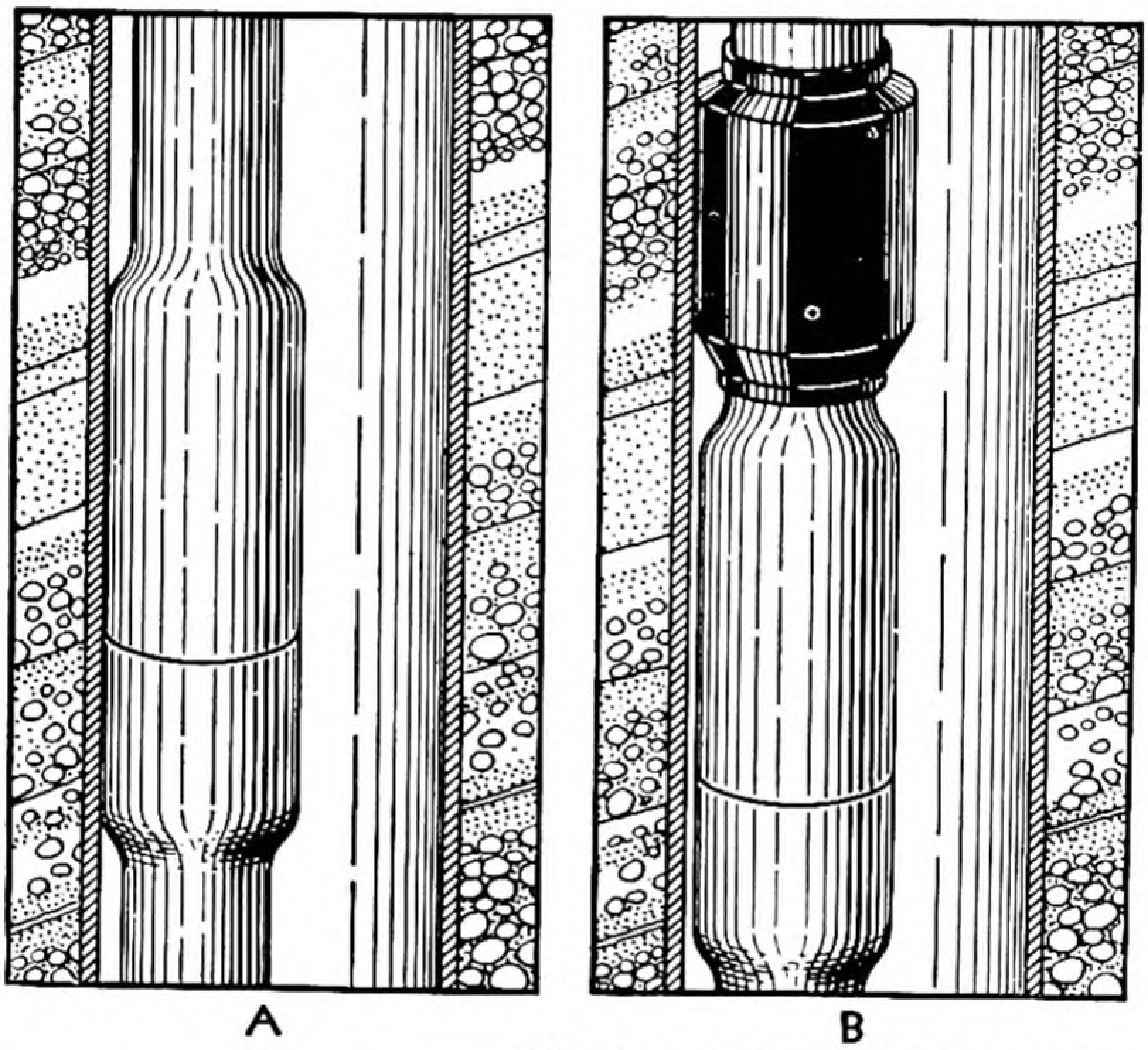


(*Courtesy of American Petroleum Institute and National Tube Co.*)

FIG. 98.—Threads and couplings used on A.P.I. standard drill pipe. *A*, internal upset pipe; *B*, detail of thread; *C*, external upset pipe.

Drill-pipe Protectors.—There is necessarily some power loss in scraping of the rotary drill-pipe collars and tool joints against the wall of the well or the interior of any casing through which drilling operations may be conducted. Such friction also results in wear of the casing and drill stem, often to a highly detrimental degree, perhaps leading to failure of the drill pipe at a weakened joint and leaking or even collapse

of the casing under stress developed by high hydrostatic head. To overcome these disadvantages partly, many operators equip the drill column with rubber protectors. These are made of heavy cylindrical blocks of rubber molded to fit snugly on the outer surface of the drill pipe (see Fig. 99). They are slightly larger in external diameter than the tool joints, and one is placed near each tool joint and pipe collar. All rubbing surfaces are rubber against metal, a combination



(*Courtesy of Bettis Rubber Co., Ltd.*)

FIG. 99.—Use of rubber protectors on drill pipe. *A*, metal-to-metal contact wears out drill pipe and casing; *B*, rubber protection with mud lubrication eliminates abrasion.

which occasions much less wear and friction than metal against metal, particularly in the presence of a gritty fluid.

Use of rubber as protection against frictional drag and wear of the drill pipe is also exemplified by the so-called "antifriction" tool joints and collars in which a groove is machined to receive and support the rubber cylinder. The same principle is made use of in the Bettis drill stabilizer, a large rubber cylinder placed on the lower end of the drill pipe a short distance above the bit. This device aids in keeping the hole straight and avoiding twistoffs of the drill column, by minimizing eccentric motion, bending, "whip" and torsional stress.

The Drill Collar.—Originally, the drill collar was designed merely to provide a means of attaching the drilling bit to the drill pipe and to strengthen the lower end of the drill column, which is subjected to destructive compression, torsion and bending stresses. More recently, the drill collar has been called upon in addition to fulfill an even more

important function: that of concentrating a heavy mass of metal near the lower end of the drill column. As will be explained in a later section (see page 311), this is a desirable condition in providing security against twistoffs and in stabilizing the motion of the drill column when operated with high bit pressure and at rapid rotational speed, as required in modern rotary drilling practice. Whereas drill collars were formerly but a few feet long and weighed only a few hundred pounds, they are now at times as much as 180 ft. long and may weigh 8 tons or more.

Drill collars are preferably made of forged alloy steel carefully heat-treated, machined to cylindrical form and longitudinally bored so that they are perfectly straight and of uniform wall thickness. They may be obtained in lengths up to 60 ft. with a tool-joint box integrally formed on each end. If a longer drill collar is desired, two or more may be coupled together with double-pin subs. At the upper end, the drill collar is attached to the lower end of the column of drill pipe, while at the lower end it supports the drilling bit.

The A.P.I. has adopted certain standards for drill-collar dimensions, threads, character of joints, etc. Standard sizes ranging from $2\frac{3}{8}$ to $6\frac{5}{8}$ in. are provided, corresponding to the designations of the size of drill pipe on which they are run. Minimum lengths of 6 or 8 ft. are specified, depending on diameter. The outside diameter of the drill collar is the same as that of the tool joints for the particular size of "string" upon which it is to be run. Inside diameters range from $1\frac{1}{2}$ to $3\frac{1}{2}$ in. Recesses are often machined in the outer surface of the drill collar to facilitate operation of the elevator and overshot. Unless the threads provided in the lower box of the drill collar are of suitable type, it may be necessary to use a double-pin sub to connect with the drilling bit.

Grief Stems or "Kellys."—In order that the rotary table may have a positive grip on the drill column, so that it must rotate with the table, the upper end of the column is provided with a "grief stem" or "kelly" of angular form, designed to fit a similarly shaped opening extending through the driving bushing of the rotary table. The grief stem may be either square, hexagonal or fluted (cruciform) in cross section (see Fig. 91). Sizes range from $2\frac{1}{2}$ to 8 in. for the square kellys, and $5\frac{1}{2}$ to 7 in. in diameter for the fluted variety. For use with range 3 drill pipe (38 ft. or more) and with range 1 pipe (18- to 22-ft. lengths) made up in "doubles," the kelly may conveniently be 55 ft. long. The A.P.I. standard grief stem is 38 to 41 ft. long and is designed for use with range 2 drill pipe (27- to 30-ft. lengths).

Because of the severe stress to which the grief stem is subjected in service, it should be constructed of alloy steel, carefully forged and heat-treated, and machine-finished so that it passes smoothly through the table bushings. To assure symmetry and balance, the stem should be absolutely straight and the cylindrical bore should be in the exact longitudinal axis or geometrical center of the metal cross section. Grief stems are connected in the drill column by threaded joints of two types: (1) the coupling type and (2) the integrally formed joint type. In the latter, the ends are upset to form a tool-joint connection: a "box" on the upper end to connect with the coupling on the lower end of the rotating sleeve of the swivel, and a "pin" on the lower end to

connect with a tool-joint box on the upper end of the top joint of drill pipe. The coupling type of grief stem is provided with a pin joint at each end, for connection to special top and bottom couplings. The upper grief-stem couplings are cut with left-hand threads, the lower with right-hand threads. Special "subs" may be necessary to adapt the grief-stem threads to the threads provided on the drill pipe, or to permit use of a grief stem with various sizes of drill pipe.

Rotary Drilling Bits.—The cutting tool, which is, in a sense, the focal point of the entire rotary drilling rig, is mounted on the lower end of the drill column, attached to the drill collar by a tool joint or a sub. The bit disintegrates the rocky material in its path by its rotation and by the downward pressure imposed upon it by the weight of the drill column. By proper design of the cutting elements of the bit, a scraping, cutting and chipping action is thus developed on the formation exposed in the bottom of the well, disintegrating the material into fine granular fragments or, in some types of rocks and with some bits, forming larger chips or flakes.

Many different styles of bits are used in rotary drilling, a choice depending chiefly upon the nature of the formation to be penetrated and the individual preference of the operator. An entire cylinder of the formation, having a diameter slightly greater than that of the drilling bit, is thus removed. With some styles of bits, only a ring of rock around the perimeter of the hole is disintegrated, leaving a core of material in the center of the hole to be removed by a "core barrel." We shall here be concerned only with the styles of bits that accomplish complete disintegration of the material in the path of the drill, reserving the discussion of coring tools for a later chapter.

The first type of bit developed for use with rotary equipment was the fishtail bit, still widely used in drilling soft unconsolidated and semiconsolidated formations. It is especially adapted for use in loosely cemented sands, shales and clays. When used in harder rocks, it is rapidly dulled and progress is slow. Various forms of fishtail bits are illustrated in Fig. 100. They are made of a special grade of tool steel, often of chrome steel, forged to a slender blade ranging from 15 to 30 in. in length, ½ to ¾ in. thick at the cutting edge and 1½ to 2½ in. thick at the top. The top of the flattened portion of the bit terminates in a round shank on which is machined either the pin or box end of a tool joint for connection with the drill collar or a connecting sub. The width of the blade at the cutting edge is only slightly smaller than that of the hole which it is desired to drill. The cutting edge is divided into two parts by fluted water courses down the center of each side of the blade. The two cutting wings thus formed are dressed to a slight taper or bevel and turned back slightly to form the cutting edges. Through each side of the shank, a hole ¾ to 1½ in. in diameter is bored. Drilling fluid from the drill column emerges through these holes, sweeps down the side of the bit and is deflected upward on striking the bottom of the hole, thus keeping the space around the cutting edges free of accumulated cuttings.

Special forms of fishtail bits are shorter and are designed to discharge the drilling fluid nearer the corners and cutting edges than in ordinary patterns, as illustrated in Fig. 100*B*. These features are said to aid in getting quickly drilled, dense clays and

shales into suspension in the well fluid, preventing the material from "balling up" on the bit and also minimizing the tendency of the cutting edges and corners to overheat when drilling in harder rocks. Other forms of "drag" bits include the "four-wing" bit (or "four-way" bit), with four blades, each shaped like half of a fishtail bit, set at right angles to each other; also the "three-way" bit and the diamond-pointed bit. These tools are used primarily for straightening and reaming holes that have become crooked or have lost clearance.

Another type of rotary bit, useful in drilling soft and moderately hard formations, is the disk bit, illustrated in three forms in Fig. 101. In this type of bit, the cutting elements consist of two or more saucer-shaped disks, so mounted that they rotate on their slightly inclined supporting pins as the tool revolves on the bottom of the hole. The edges of the disks may be dressed to a smooth, sharp cutting edge, or they may be corrugated or "marcelled." In some styles, the edges are milled to form cutting teeth.

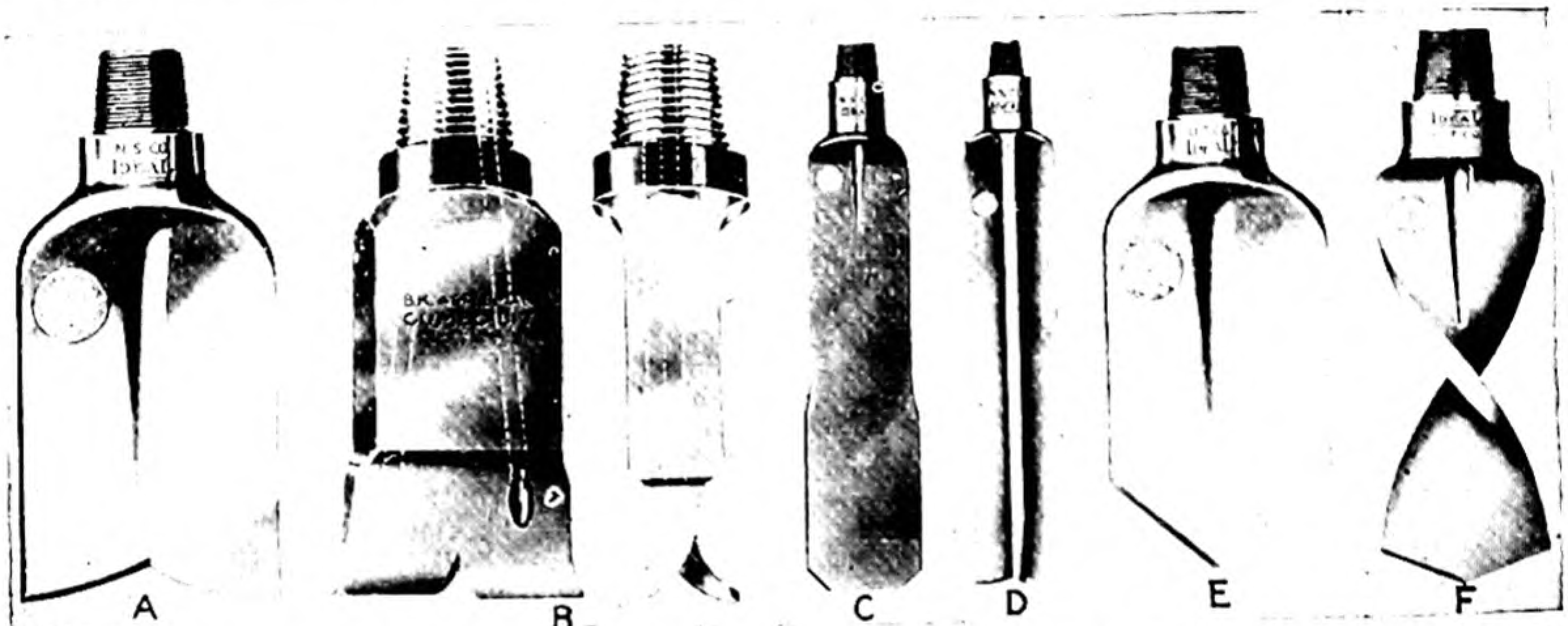


FIG. 100.—Types of fishtail and rotary reaming bits. *A*, California type "Ideal" fishtail bit; *B*, Appleman gumbo bit; *C*, "Ideal" paddle reaming bit; *D*, "Ideal" four-wing reaming bit; *E*, diamond-pointed bit; *F*, sidetracking bit.

The Zublin differential bit is a more elaborate type in which the cutting element consists of an eccentrically mounted roller presenting to the formation, as it revolves, a series of rotating disks with saw-tooth edges (see Fig. 101C). The disk bit applies a combined scraping and crushing action on the formation, effective in securing rapid advance in formations of suitable hardness. The disks are increased in diameter as the diameter of the hole to be drilled is increased. They have many times as much linear cutting edge as a fishtail bit used in drilling a hole of the same size, and therefore are capable of a greater footage of drilled hole without resharpening.

For hard-rock rotary drilling, more intricate types of bits are used, which depend upon a crushing and chipping action rather than a scraping action. Cone and roller bits, designed to utilize this principle, are well known and widely used, for drilling not only in hard rocks, but in formations of all types. The Hughes bit was the pioneer cone bit, but early patents have expired and cone bits are now made by several other manufacturers. The modern cone bit is a product of many years of development, during which many different models have been manufactured and extensively used in the petroleum industry. Earlier models of cone bits were equipped with two cones, on the surfaces of which were milled a large number of cutting teeth. The cones revolve on supporting pins in such a way that the elements of the conical surfaces in contact with the bottom of the hole are almost horizontal or, preferably, inclined a few degrees below the horizontal from the axis of the tool. In addition to the cone cutters, cylindrically shaped reamers were sometimes mounted on the side of the tool.

A preferred current model of Hughes cone bit incorporates three cones, mounted

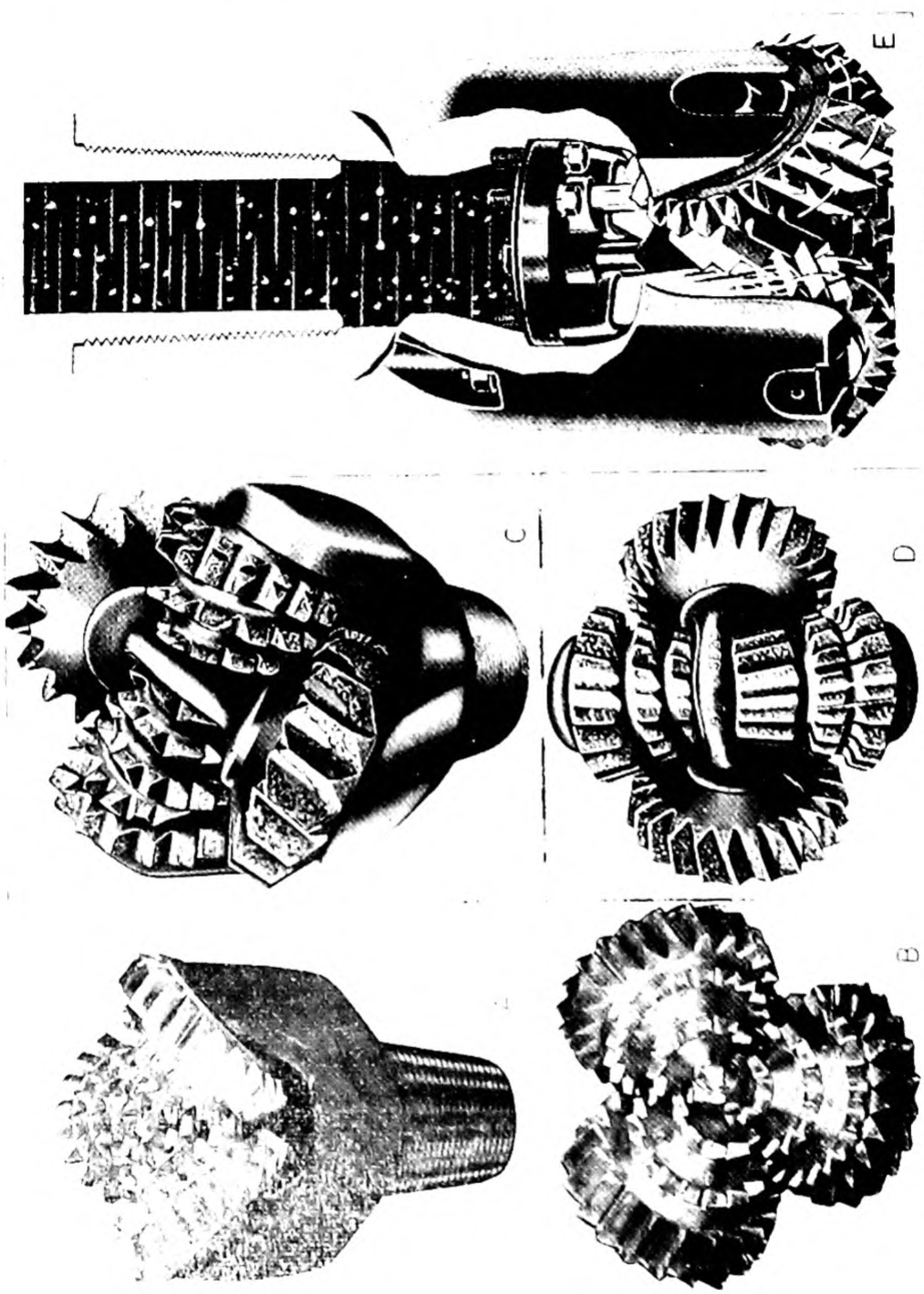
radially in a supporting body, 120 deg. apart in a horizontal plane (see Fig. 102). These bits are unitized, so that all parts are fastened permanently together in working position. No accessories or spare parts are required. Streamlined, forged-steel bodies provide a large factor of safety. The bearing pins that support the cones are forged integrally with the supporting shanks. The cutting elements turn on ball and roller bearings that assure free motion under high pressure, with a minimum of friction. The cutting elements are hard-faced with tungsten carbide to assure long service and high "footage." Water courses through the tool provide high-speed jets that impinge

FIG. 101.—Types of disk bits. *A*, Byron-Jackson two-disk bit; *B*, Guiberson four-disk reaming bit; *C*, sectional view and *D*, exterior view of Zublin differential bit.

directly on the top of the cone surfaces, keeping them cool and free of adherent clay. Some models of Hughes cone bits have self-cleaning teeth that interlock as they rotate, thus squeezing out sticky material that tends to ball up on the bit. The cones are available with cutting teeth arranged in a variety of different patterns, designed to adapt them to varying operating conditions and to formations of different hardness. For hard formations, shallow, closely spaced teeth are preferable, while for soft formations, the teeth should be more widely spaced and deeper cut. For unconsolidated and semiconsolidated formations, the teeth may be arranged in spiral rows around the cones to prevent "tracking."

The roller type of rock bit has been and is a close competitor of the cone bit and is regarded as equally efficient by many drillers. This type of bit has experienced a gradual development and evolution through many models to the highly efficient roller bits manufactured today. The Reed roller bit was the pioneer bit of this type, and is today best known. The currently manufactured model of Reed roller bit comprises

four supporting shanks 90 deg. apart, molded together to form a smooth, streamlined body (see Fig. 102). Each shank supports one of four cutting elements, hard-faced with tungsten carbide. Two of these are in the form of disks with teeth cut on their edges, supported in an inclined position. The other two are in the form of rollers with



(A–B, courtesy of Hughes Tool Co.) (C–E, courtesy of Reed Roller Bit Co.)

FIG. 102.—Types of cone and roller bits for hard-rock rotary drilling. A, tricone bit, side view; B, tricone bit, bottom view; C, roller bit, diagonal view; D, roller bit, bottom view; E, sectional view of roller bit showing method of discharging drilling fluid.

spiral rows of teeth on their surfaces, mounted end to end, so that they revolve in an approximately horizontal position with elements of their cylindrical surfaces bearing on the bottom of the hole as they revolve. The latter are of different lengths, so that they rotate eccentrically and, for added security, are trussed together (see Fig. 102). The cutting elements rotate on ball and roller bearings, assuring free rotation with minimum friction, even under high bit pressure. The cutters and their supporting

pins and shanks comprise a unitized assembly, not intended to be disassembled outside of the manufacturer's plant.

Cone and roller bits are capable of making better progress and a much greater footage than is possible with fishtail or disk bits, particularly in hard rocks. This is, in part, due to the more efficient principle on which they operate and, in part, to the greater length of cutting edge which they present. For example, in three 9⅞-in. cone cutters of one pattern, there are 84 teeth, each 3 in. long, or a total of 252 in. of cutting edge, as compared with perhaps 11 in. for the ordinary fishtail bit. The teeth and cutting edges of rock bits, of course, gradually wear away under the abrasive action of the formation. Their serviceability is greatly increased by hard facing and reinforcement of the critical edges and surfaces with tungsten carbide.

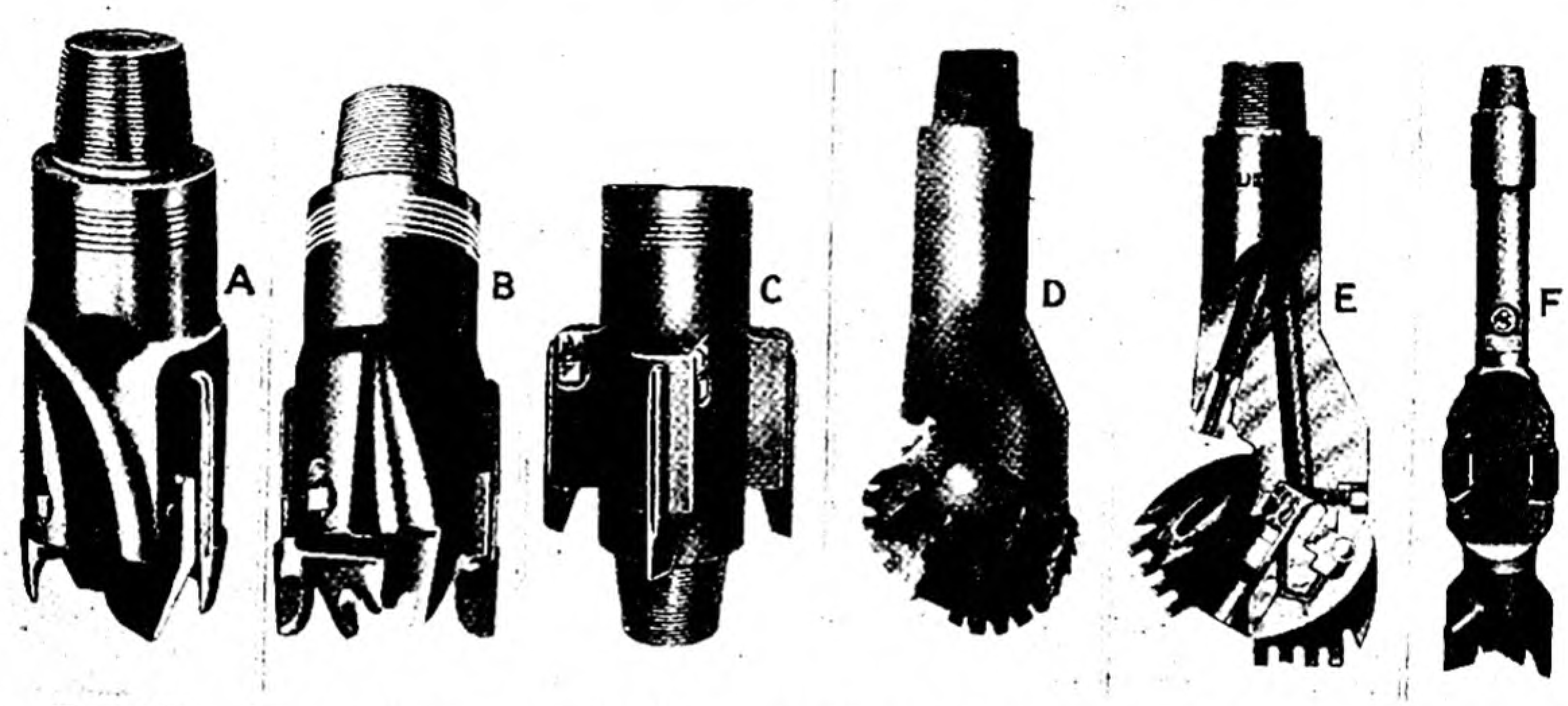


FIG. 103.—Types of demountable bits. *A*, *B* and *C* are different styles of Kennedye-Plumb replaceable-blade bits and reamers; *D*, external view and *E*, sectional view of Zublin bit; *F*, Smith demountable bit and reamer.

Still another group of rotary bits, known as "demountable bits," are equipped with detachable drill heads on which prongs or cutting teeth are cast or otherwise attached, in such a way as to attack the formation from various angles as the tool revolves. Instead of trying to resharpen, the entire head of the tool is replaced by a new one when necessary. Figure 103 presents several different styles that are illustrative of this type. In a somewhat similar tool, merely the cutting teeth or blades of the bit are replaced (see Fig. 103*A*, *B*, *C*). The Zublin bit is an interesting member of this group (see Fig. 103*D*, *E*). In this, the head is equipped with heavy, prong-shaped teeth, projecting out at various angles, and is mounted so that it turns eccentrically as the massive steel body of the tool revolves with the drill column. The cutting head is mounted on ball bearings to reduce friction. The peculiar method of mounting provides both up-and-down as well as rotating motion for the cutting teeth, so that they function as both hammers and chisels. The manufacturer claims that it is efficient in any kind of formation, drills rapidly, mixes the cuttings with the fluid thoroughly and is "self-sharpening," so that it maintains its cutting edges. It is claimed also that there are comparatively few twistoffs of the drill pipe with this type of bit, and that it drills a straighter hole. The Carter collapsible bit is unique in that it is possible to replace the cutters without withdrawing the drill pipe from the well. The replaceable elements are withdrawn and replaced by a steel cable operating through the drill pipe.

In order to resist breakage under the severe stresses to which they are subjected in service, rotary drilling bits are often made of low-carbon steel and then casehardened

to develop wear-resisting qualities. In heat-treatment, a compromise must be reached between hardness on the one hand and brittleness on the other. In seeking to improve the wearing qualities of drilling bits and the footage of hole drilled per bit, notable increase in drilling efficiency has been achieved by the use of hard-facing metals applied to the wearing corners, edges and faces. High-carbon steel, special alloy steels containing manganese, chromium, vanadium or tungsten, may be fused on with the aid of the oxyacetylene torch. Many different methods and systems of tempering and casehardening are employed. Tungsten carbide, available on the market in a variety of different forms and trade names, is inserted in small pieces in cavities prepared in the bit, or embedded in fusion metal applied with the oxyacetylene torch. This material, next to the diamond, is the hardest substance known. It is also tough, so that it does not readily crush or crack under the high pressures to which rotary bits are frequently subjected in service. Though expensive, these hard-facing materials are profitably used because of the greater footage secured with each bit and because of reduction in loss of drilling time in changing bits.[4]

The Circulating System

The primary function of the circulating system is to force drilling fluid down through the drill column, back to the surface through the annular space about it, and through various surface facilities designed to separate drill cuttings and to condition and store surplus fluid. The essential elements that are properly regarded as a part of the rotary rig are (1) one or more slush pumps (usually two) and their suction lines and manifold; (2) the rotary hose; and (3) the swivel. Other essential elements, apart from the drilling rig proper, are (4) the mud ditch and (5) the mud pit. In addition, the circulating system may include other useful but not essential elements, such as mud-mixing equipment, vibrating screens and various mud-conditioning devices. In the present section, we shall be concerned only with the elements of the circulating system that are a part of the drilling rig proper, reserving further discussion of the circulating system and its control for a later chapter.

Circulating Pumps.—Slush pumps in a rotary drilling rig have the function of applying pressure to the circulating fluid so that it may flow in suitable volume and with proper velocity down through the drill column and back to the surface, through the annular space between the drill column and the wall of the well. The pumps must supply an ample volume of drilling fluid at whatever pressure may be necessary to raise drill cuttings or maintain equilibrium pressure conditions within the well. This service, more than that performed by any other element of the rotary rig, determines the amount of power necessary in its operation. In a deep-drilling operation, using steam power, as much as 85 per cent of the gross power output of the boilers may be consumed in operating the pumps. Hence, we are concerned here with a very important element of the rig. In this sense, all other parts are subordinate

to and are selected primarily with regard to the required capacity and power demands of the pumps.

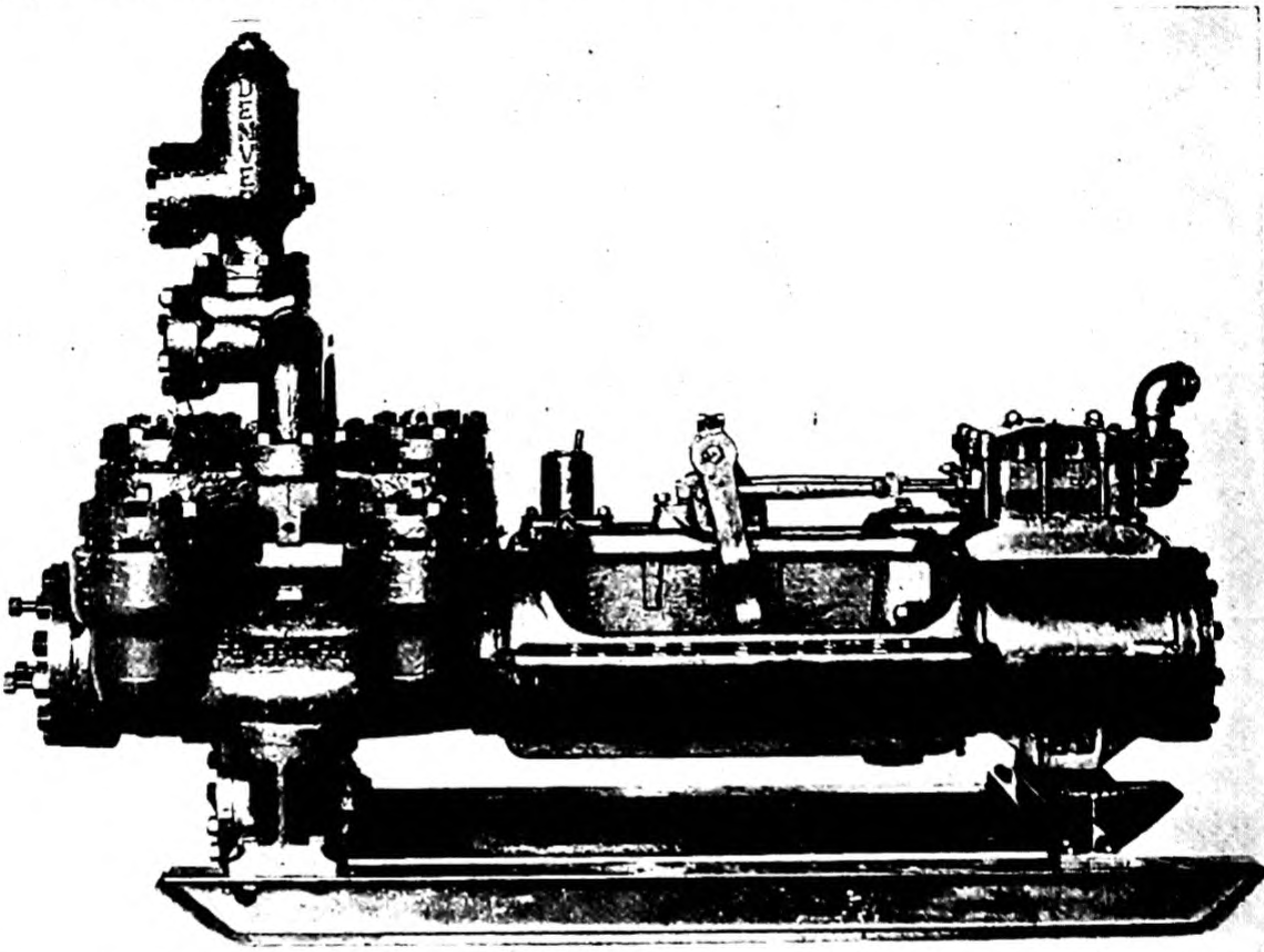
The conventional rotary drilling rig is equipped with two identical slush pumps, either of which may be used separately or compounded with the other. In earlier rotary drilling practice, wear on the pump valves and liners was so rapid that interruptions in service were frequent in order to make repairs or replacements of pump parts. Two pumps were necessary so that one might always be available while the other was being repaired. During recent years, improvements in materials and design have developed pumps that require comparatively little maintenance and are seldom out of service. Accordingly, some operators now provide only one modern pump for an ordinary drilling operation. In drilling deep wells, however, where demands on the pump are likely to be severe, two pumps will usually be provided, though one of them may be an older model intended primarily as a stand-by unit.

Circulating pumps may be either of two principal types: (1) steam-driven double-acting, duplex or triplex pumps in which steam and water cylinders are placed end to end, a single piston rod serving both; (2) power pumps of duplex type, equipped only with water cylinders and designed to be operated by a belt, gear, hydraulic or chain drive from a separate prime mover, which may be a steam engine, internal-combustion engine or an electric motor. Power is transmitted to the horizontally reciprocating pump pistons through the instrumentality of a pair of cranks and connecting rods operating on a power-driven crankshaft.

A power pump differs fundamentally from a direct-acting steam pump in its operating characteristics. A power pump is designed to operate at constant speed and lacks the flexibility in speed and capacity exhibited by the direct-acting steam-driven pump. The pump and prime mover must be closely coordinated in order that the pump characteristics may be appropriate for the service required. If the well resistance temporarily increases, as often happens in rotary drilling, the direct-acting steam pump automatically reduces speed or may even stall without damage. Under such conditions, the power pump tends to continue operating at the same or only slightly reduced speed, perhaps imposing an excessive load on the prime mover. A d-c motor can readily adapt to such a condition, but an a-c motor or an internal-combustion engine cannot readily do so. These prime movers, however, may be adapted to slush-pump operation by driving the pump through a torque converter or hydraulic coupling.

If the rotary rig is steam powered, the pumps will generally be of the direct-acting type (see Figs. 104 and 105). These pumps are rated by the diameter of the cylinders and length of piston stroke. Steam cylinders range from 10 to 20 in. in diameter,

the water cylinders from 5 to 8 in. and the stroke from 12 to 24 in. Thus, an 18- by 7- by 20-in. pump of this type has 18-in. steam cylinders, 7-in. water cylinders and a 20-in. piston stroke. Steam ends are designed for pressures ranging from 125 to 400 lb. per sq. in. Capacities depend upon the steam pressure, operating speed and efficiency of the pump. With 350 lb. steam pressure and maximum speeds, the larger pumps are capable of delivering upward of 2,000 gal. of drilling fluid per minute. Normally, however, from 700 to 800 gal. per min. will meet all requirements and this may be achieved with from 40 to 60 strokes per minute. Normal pumping speeds should not exceed 120 ft. of piston travel per minute. Steam ends of cast steel, though designed for working pressures of 400 lb. or less, are secure against test pressures as



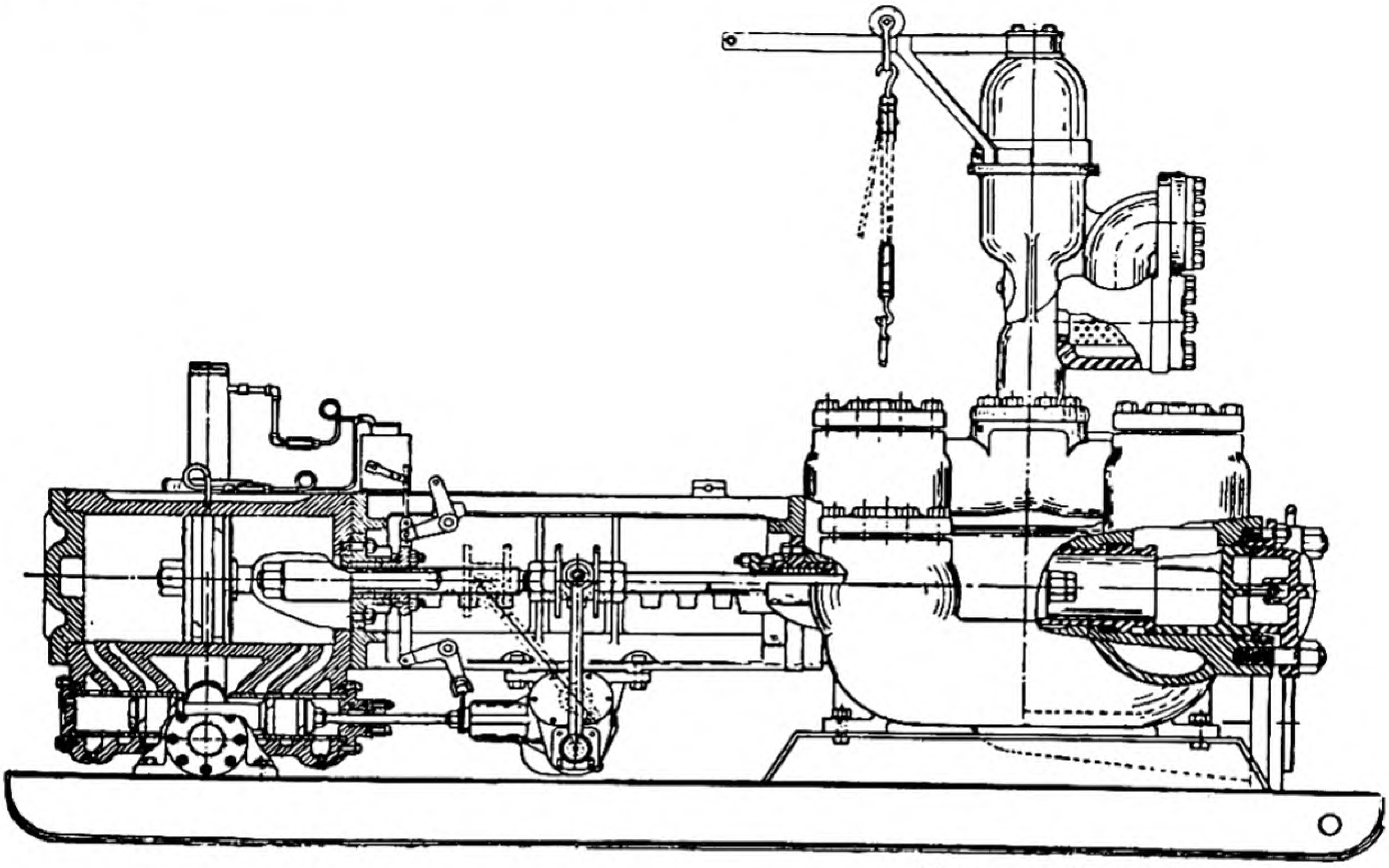
(Courtesy of Emsco Derrick and Equipment Co.)

FIG. 104.—Heavy-duty slush pump.

high as 800 lb.; and water ends, of welded steel forgings, designed for working pressures up to 3,000 lb. per sq. in., will stand test pressures as high as 6,000 lb. Volumetric efficiencies (*i.e.*, actual delivery capacity divided by theoretical displacement capacity) may range as high as 85 per cent, but average about 60 per cent when pumping the heavy muds used in rotary drilling. Weights range up to as much as 29,000 lb. for the larger sizes of direct-acting steam pumps.

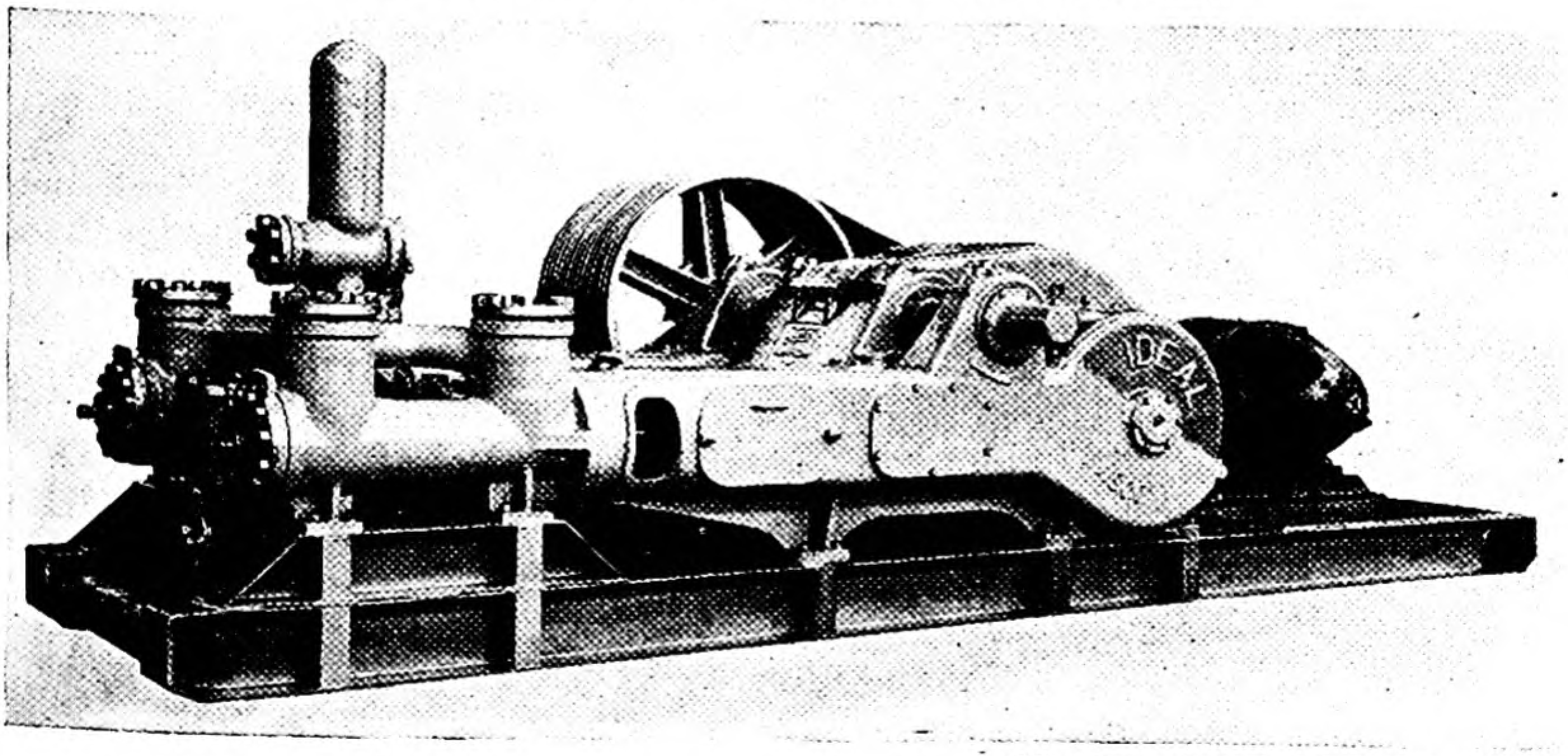
Power pumps were originally designed for use on rigs powered with electric motors or internal-combustion engines, but more recently it has been found advantageous to use them with separate steam engines. The ordinary direct-acting pump is not efficient in its use of steam, inasmuch as there is no provision for steam cutoff and there is no flywheel effect to smooth out the motion. A separate, well-designed steam engine equipped with a device for regulating the steam cutoff, and connected to the pump drive shaft with a multibelt drive, may operate with only 60 per cent as much steam as a direct-acting steam pump of equivalent capacity. Figure 106 illustrates a typical power pump with integrally mounted reduction gear to adapt the com-

paratively high rotational speed of a motor or internal-combustion engine to the 40 to 60 reciprocating strokes of the slush pump. A part of the speed reduction may also be accomplished by a belt or chain drive or a torque converter or hydraulic coupling.



(*Courtesy of Lucey Export Corp.*)

FIG. 105.—Direct-acting duplex steam slush pump.



(*Courtesy of National Supply Co.*)

FIG. 106.—Slush pump driven by electric motor through speed reduction gear.

Construction details of the water end of the slush pump are much the same, whether of the direct-acting or power-driven type. The cylinders are equipped with removable, hardened steel liners of varying interior diameters. By using smaller liners, the fluid delivery pressure may be increased without increasing the steam

pressure on the steam end, or speed or power input to the pump drive shaft. This, however, is accomplished at the expense of volumetric capacity. Thus, when drilling a large-diameter hole at shallow depths, a large volume of fluid is required and the necessary delivery pressure of the circulating fluid may be only 200 lb. per sq. in. or less. For such an operation, the pump liners in the water cylinders may be 6¾ or 7¼ in. in diameter. At greater depths, with smaller diameter hole, a smaller volume of fluid will be needed but the delivery pressure must be greater to offset the increased well friction. Smaller liners, perhaps 5 or 6 in. in diameter, may be used at this stage. For great depths, or for special operations, very high fluid pressure may be necessary and liners as small as 3½ in. may be used in the water cylinders.

Because of the nature of the fluid handled, it is important to have the valves, liners, packing glands and other wearing parts conveniently accessible for repairs. Steam valves are usually simple slide valves, positively controlled by rockers actuated by the pistons (see Fig. 105). The water suction and discharge valves are of the wing-guided disk type, operating against heavy springs coiled about the valve stems. Valve seats are usually faced with hard rubber to ensure tight seating and adjust for wear. Valve areas on the water end are large, to adapt them to use with viscous drilling fluids that often carry gritty sands. In modern designs, fluid passages are made as large as possible and are streamlined to reduce flow resistance.

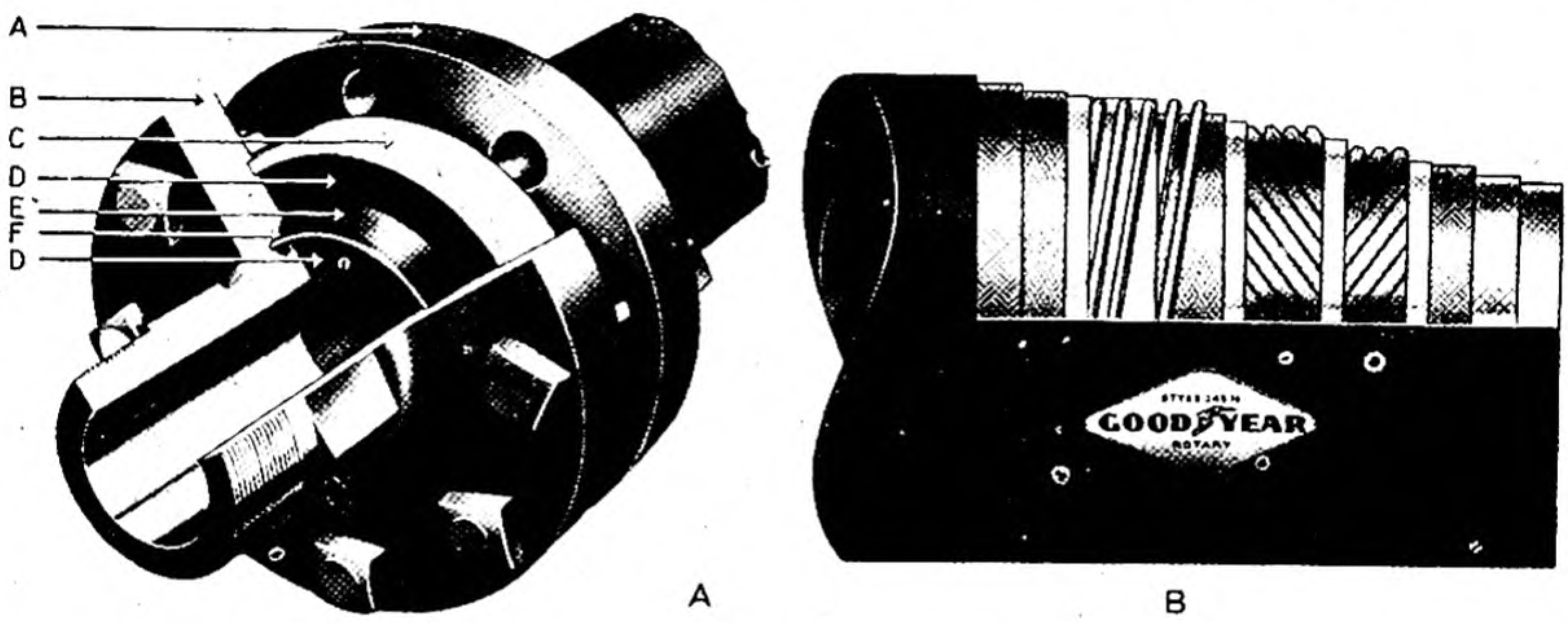
The conventional position for the slush pumps in the rotary rig is on the derrick floor, on the side opposite the draw works (see Fig. 26). With the larger, heavier pumps necessary in deep drilling, it becomes necessary to place them outside of the derrick on separate foundations and, if necessary, with separate housing. In this event, the pumps will be placed at one side of the derrick and preferably near the mud pit (see Fig. 78). On sloping ground the mud pit and pumps will necessarily be on the lower side of the rig. In a steam-powered rig, the pumps consume a large part of the steam supply; hence there is economy in steam transmission in placing the pumps as near the boilers as other conditions will permit. Also, in the event that a high-pressure well gets out of control, the pumps are in a safer position and may be operated with greater security if situated a little distance away from the rig. Yet, they should not be so far removed from the rig that they cannot readily be watched by the driller and reached quickly for adjustment and control in an emergency.

The pumps draw their supply of fluid through suction lines equipped with foot valves or strainers well immersed in the mud pit. Individual suction lines should be of a diameter sufficiently large to interpose a minimum of flow resistance, often 6 or 8 in., but preferably not less than 10 in. Right-angle bends in the suction lines should be avoided. Joints should be secure against leakage. Flanged connections are preferably used. The suction lines should be as short as practicable. The suction lift should never exceed 15 ft. and in order that the lift may be as small as possible, the pumps are preferably placed on foundations at or near ground level, rather than on an elevated platform.

The pumps discharge their fluid under pressure into a pump manifold, equipped with appropriate valve control. From the pump manifold, a pipe line secure against high pressure carries the fluid to the standpipe in the derrick. This is a pipe, 3 to 6 in. in diameter, extending about 40 ft. up one corner or one side of the derrick, and provided at its upper end with a suitable connection for the rotary hose which carries the fluid to the gooseneck of the swivel. Valves used in the pump manifold and connecting pressure lines should be of quick-closing type to permit of quickly changing flow from one pump to the other. Grease-packed cocks are conveniently used for this purpose. All pressure lines should be securely anchored to minimize vibration which may be induced by pulsation of the pumps. To absorb pulsations further and to induce uniform flow in the delivery lines, an air chamber is generally provided on

each pump. The pump connections should be so manifolded that, by merely adjusting valves, the pumps may operate individually or compounded, and either in series or in parallel.

Rotary Hose.—The flexible connection between the standpipe and the gooseneck of the rotary swivel usually consists of an armored hose constructed of rubber, heavy duck fabric, wire and metallic mesh. For use with oil-base drilling fluids, rotary hose is available, constructed of neoprene or other synthetic rubber resistant to oil. Heavier grades of rotary hose are capable of withstanding test pressures as high as 5,000 lb. per sq. in., or the maximum pressures encountered in drilling operations. A hose 60 ft. long is necessary to provide for the vertical movement of



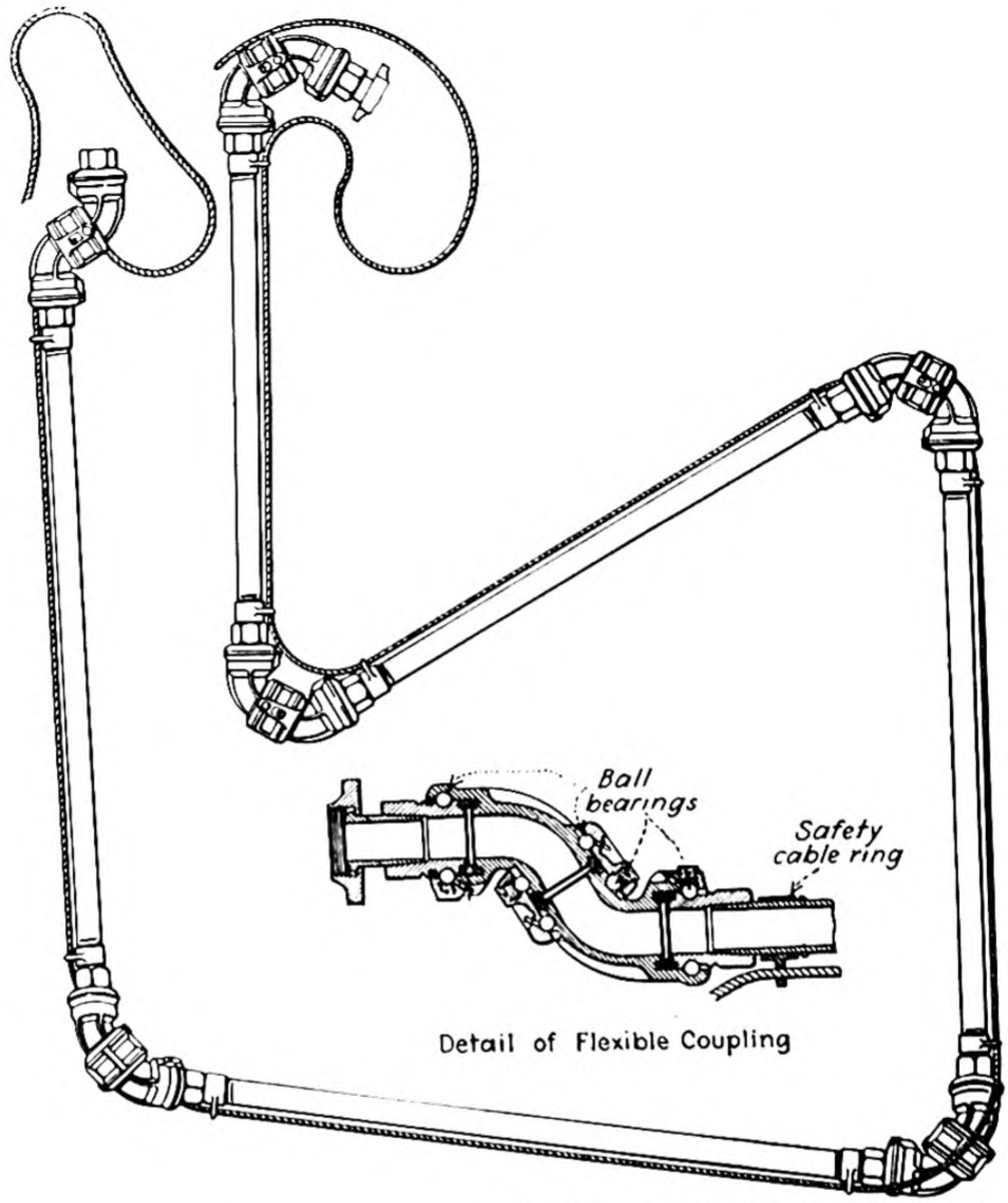
(Courtesy of The Goodyear Tire & Rubber Co., Inc.)

Fig. 107.—Armored rubber hose with integral flange for connection between swivel and standpipe in rotary drilling rig. **A**: integral flange and connecting elements; *A*, metal backing ring; *B*, metal flange adapter; *C*, metal retaining ring for integral rubber flange; *D*, rubber-faced integral flange with sealing flute integral with rubber face, *E*; *F*, adapter sealing recess. **B**: sketch illustrating construction of armored hose.

the drill column. This may be a single hose of this length, or two 30-ft. lengths connected by a secure coupling.

High pump pressure, necessary in deep drilling, has necessitated development of special couplings for connecting the rotary hose with the swivel gooseneck and with the return-bend connection at the upper end of the standpipe. Primitive couplings make use of special types of hose clamps, designed to compress the ends of the hose against their metal connections. These are destructive of the hose structure and occasionally fail under the high pressures with which they must sometimes contend. A superior method of connection is found in the use of integrally constructed hose flanges and couplings (see Fig. 107). These provide metal-flanged or screw connections that are directly supported by the metal reinforcement used in the construction of the hose, and for all practical purposes are integral parts of the hose. They are secure against blowouts under any pressures that may be imposed in the routine of drilling.

In operations where high pump pressures are occasionally necessary, some drillers prefer to use all-steel rotary hose to connect the swivel with the derrick standpipe. In this, the necessary flexibility is attained by use of relatively short lengths of steel tubing, connected by ball-and-



(*Courtesy of Oil Equipment Sales Corp.*)
FIG. 108.—Hamer all-steel rotary hose.

socket joints or ball-bearing joints of special design. The greater the pressure, the less tendency there is for this type of joint to leak. One variety of all-steel rotary hose, constructed as illustrated in Fig. 108, makes use of seven joints of 3½-in. 12-lb. drill pipe, connected by ball-bearing joints. The several joints are tied together with a light steel cable.

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CHAPTER VIII

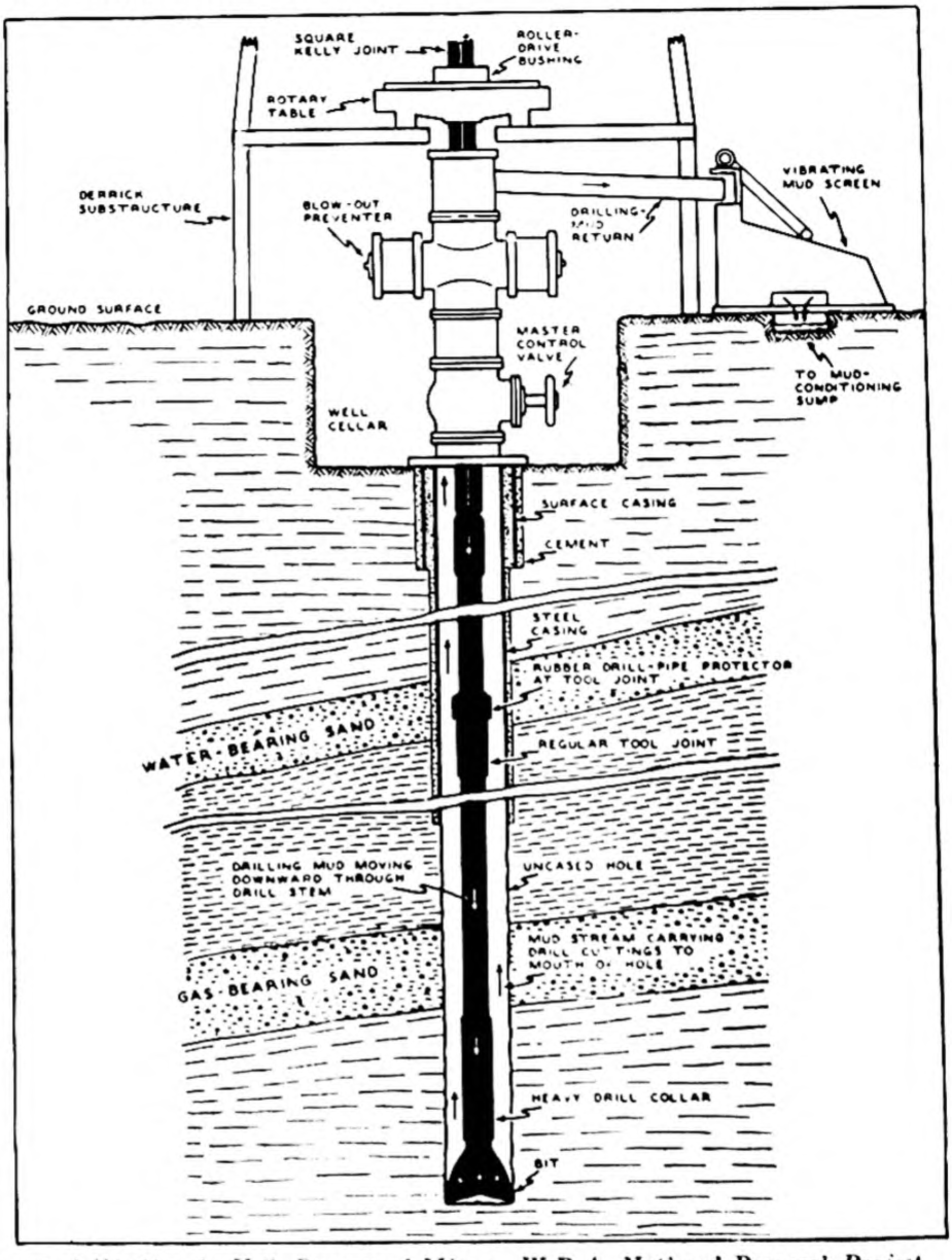
ROTARY DRILLING: THE CIRCULATING SYSTEM AND ITS CONTROL

Much depends upon proper functioning of the circulating system in rotary drilling. Prompt and continuous removal of the material loosened by the drill prevents accumulation of the drill cuttings and "freezing" of the drill pipe. Deposition of clay on the walls of the well and within the pores of the wall rocks minimizes the tendency of the walls to cave; lubricates the drill pipe, reducing frictional power loss; prevents loss of fluid into very porous, low-pressure formations so that circulation of drill cuttings to the surface will not be interrupted and seals off high-pressure gas- and water-yielding horizons so that fluids from them cannot enter the well, thus preventing a destructive blowout; and absorbs the heat caused by friction of the drill pipe and bit on the walls and bottom of the well. These are matters of prime importance, especially in deep drilling, and their successful accomplishment requires close control of the volume, pressure and physical characteristics of the fluid circulated.

The circulating medium, as we have seen, is usually a clay-laden fluid. This fluid, under the propulsion of powerful pumps, is forced through the pump manifold, the flexible hose and swivel and thence down through the drill pipe and out into the well through holes in the bit. Jetted against the bottom of the well with high velocity, the circulating fluid is deflected upward and flows back to the surface between the drill pipe and the walls of the well, carrying in the ascending stream the cuttings formed by the drill. At the surface, fluid and drill cuttings are discharged into a wooden or sheet-iron launder or flume of gentle slope in which the coarser and heavier particles are settled out by gravity. In many modern installations, the circulating fluid is passed through a rapidly vibrating screen on which the drill cuttings are segregated. Sand-free fluid is discharged from the mud ditch into a mud pit in which surplus fluid is stored, later to be drawn into the pump suction lines for further circulation through the well (see Fig. 109).

The Mud Ditch and Pit.—The mud ditch is usually a wooden flume about 2 ft. wide and 100 or 125 ft. in length, built around two sides of the derrick, with several right-angled turns (see Fig. 26). Large rectangular settling boxes are sometimes provided at each angle in the

flume. The joints are filled with pitch or asphalt to reduce leakage. The slope should be only about 1 ft. between the two ends, so that the mud flows sluggishly. The greater part of the length of the ditch is about 1 ft. deeper than the outlet, thus allowing for accumulation of



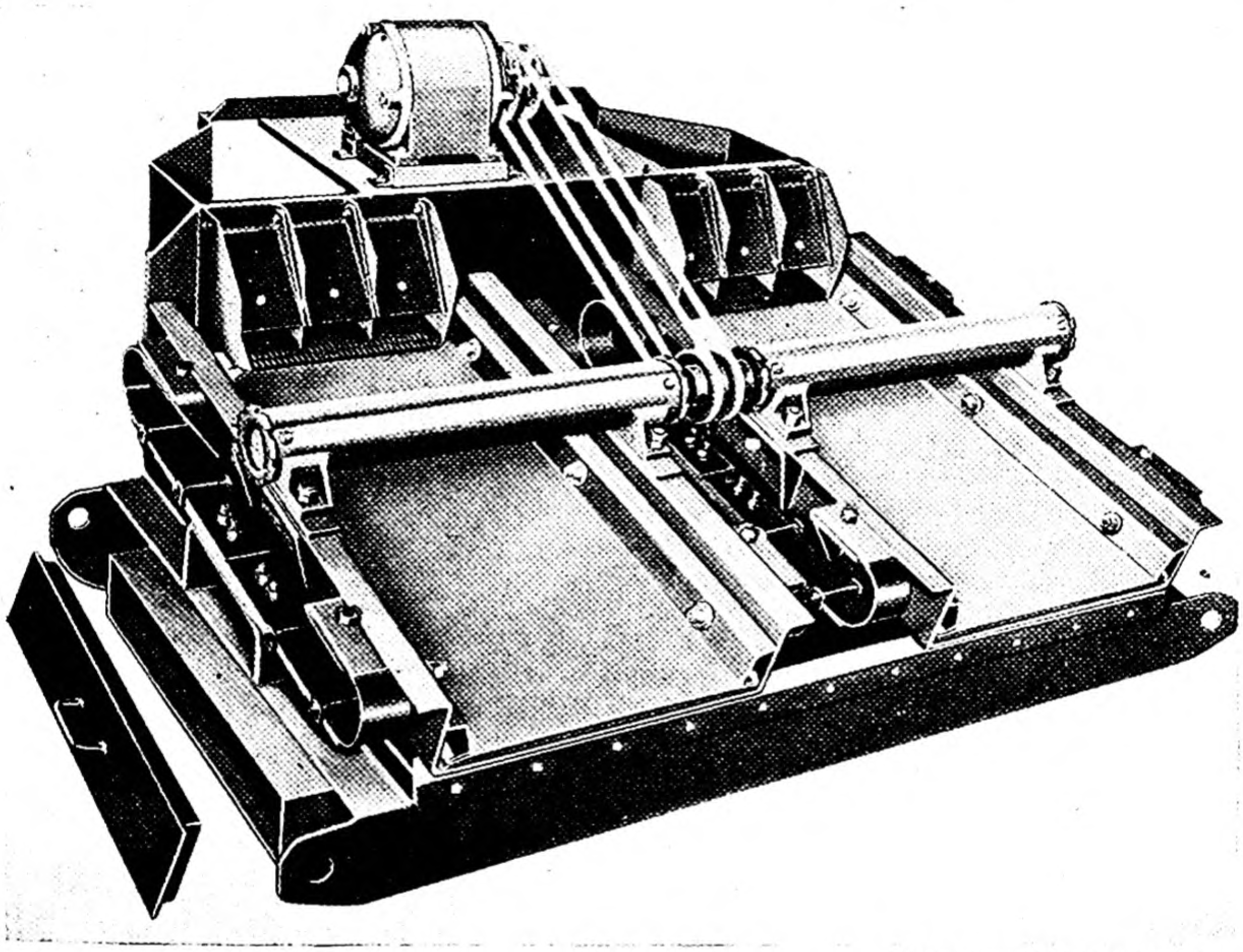
(*After Ross and Kirsling in U.S. Bureau of Mines—W.P.A. National Research Project E-124.*)

FIG. 109.—Sketch showing circuit of drilling fluid through the well in rotary drilling.

drill cuttings which must be occasionally excavated with shovels or drawn off through bottom gates.

The mud pit is often a timber-lined excavation about 8 by 12 ft. in cross section and 5 ft. deep. Vertical cylindrical tanks of sheet metal are sometimes used for mud storage, in lieu of a mud pit. Frequently an ordinary mud pond with sloping earthen embankments is used for storage of fluid. Some operators prefer to use two or three separate pits, one serving as a settling pit, another as a storage pit and perhaps a third as a pump suction pit.

Sand-separating Devices.—A simple settling ditch, as described above, may not be entirely effective in settling all sand from the drilling fluid. Gradually accumulating in the mud pit and in the fluid circulated through the well, this sand may result in "freezing" the drill pipe or bit. It also has a detrimental scouring effect upon the exposed interior surfaces of the pump, swivel and drill stem. The lubricating and wall-building properties of the clay-laden fluid are also greatly reduced by



(Courtesy of Link-Belt Co.)

FIG. 110.—Vibrating screen for separating drill cuttings from drilling fluid.

entrained sand. To effect more complete elimination of sand and coarse particles in suspension in the drilling fluid, some operators install vibrating screens, hydraulic classifiers or specially designed centrifuges. Release of sand from suspension in viscous drilling fluid may also be promoted by chemical treatment.

Two types of vibrating screens are in common use. One is vibrated by electromagnetic and the other by mechanical means. The amplitude and rate of vibration are adjustable in each case. One type of mechanically vibrated screen that has been successfully adapted to the removal of sand from drilling fluid vibrates at the rate of 1,800 times per minute and is screened with 30- to 60-mesh wire cloth 3 by 5 ft. in size, supported

at an angle of 15 to 30 deg. from horizontal. It is placed in the circulating system between the well discharge and mud-storage pit and may be operated by a 1-hp. electric motor or small steam turbine. Two such mechanical screens are used at each well (see Fig. 110). Such screens are also successful in separating entrained gas from viscous drilling fluids.

Hydraulic classifiers, sometimes employed in conditioning drilling fluid, usually involve dilution with water and must be used in conjunction with apparatus for subsequently thickening the fluid. Although effective in removing sand, the method is too complex and the equipment is too costly for use at individual wells. However, it may be advantageously used in large-scale central-plant conditioning of drilling fluid, as described in a later section.

The Merco centrifugal separator has been successfully used in removing sand from mud-laden fluid in central reclamation plants. In this machine the centrifuge bowl is 30 in. in diameter and operates at a speed of 540 r.p.m. It is driven by a 10-hp. motor, though the operating load is less than 4 hp. at full speed. The machine has a treatment capacity of 300 gal. per min., or 10,000 bbl. per day. Operating on mud fluid in which the sand content is 40 per cent of all solids present, this machine is capable of removing from 91 to 95 per cent of the sand, though much of it is finer than 150 mesh.

Chemical reagents may be added to drilling fluids with the purpose of reducing their viscosity and increasing fluidity, thus promoting settling of sand from the fluid while impounded in sumps. The mud must later be restored to its original state by addition of other reagents.

Mud-mixing Methods and Devices.—If clays or soft shales are occasionally penetrated by the drill, the well may furnish its own mud fluid so that little or no attention need be given to preparation of it. More often, there will not be sufficient clay in the formation or it will not be of suitable character to form a satisfactory circulating medium, and clay will have to be brought to the well, perhaps from a considerable distance, and mixed with water to form a fluid of the desired characteristics.

The clay used in preparation of mud fluid may be mixed with the necessary amount of water simply by shoveling it into the mud pit and occasionally stirring the mixture with shovels or hoes. A better plan, however, is to use one or another of the several types of mechanical or hydraulic mud mixers. These may be had from equipment manufacturers or may be constructed from materials commonly available on the producer's lease. One type of mechanical mud mixer consists of a small wooden or steel tank, equipped with either a horizontal or a vertical paddle shaft, driven by a chain from a sprocket on the line

shaft of the draw works. Another type employs a tank with a wedge-shaped or conical bottom, in which the clay and water are placed and then thoroughly mixed with steam jets directed into the fluid near the bottom. Some drillers claim that steam-mixed muds have certain desirable properties developed to a higher degree than mechanically mixed muds containing the same constituents. Steam jets may be used for mixing water and clay in the mud pit. Another efficient method of mixing mud fluid, once the solids have been partly hydrated, involves forcing it through jets under pump pressure and spraying it out over the storage sump. Continued circulation in this way will prevent settling of clay from surplus fluid stored in the mud pit and will assist in maintaining uniformity in the fluid delivered to the pump suction lines.

Community Mud-mixing Plants.—Mud fluid is generally mixed in pits, tanks or mechanical devices situated at or near the well in which the fluid is to be used, but in some cases, where a number of drilling operations are under way simultaneously in the same locality, central plants have been provided at which mud fluid is prepared in sufficient quantity to meet the requirements of several or perhaps many wells. At one community mud-mixing plant in the Ventura field of California, clay mined with steam shovels was moved by motor trucks to a near-by crushing and hydrating plant. It was first passed through a pair of crushing rolls and the crushed clay then puddled with water, washed through a vibrating screen and sluiced into large tanks where it was allowed to hydrate for several days, with occasional agitation by pumping from one tank to another. Well-seasoned clay fluid, somewhat thicker than required in service, was then pumped through pipe lines to the drilling wells where it was diluted to the desired consistency. A tank full of fresh clay fluid may be kept in storage at each well where it will be available in time of emergency.

A large central plant for reclaiming and conditioning "gas-cut" and sand-laden mud fluid has also been constructed in the Ventura field. Fluid that was formerly discarded at considerable expense is sluiced through wooden flumes to the reclamation plant where it is first diluted with about four times its volume of water in Dorr bowl classifiers. Dilution releases the suspended fine sand, gas and oil, and the mud is then restored to proper density and viscosity by treatment in a large Dorr traction thickener. Reclaimed mud, stored at the plant in large tanks, is pumped to the wells, the mud-distributing lines being maintained under pressure so that a valve has merely to be opened at any of the wells to receive an ample supply of fresh fluid. This plant is capable of conditioning 10,000 bbl. of mud fluid daily and serves as many as 20 drilling wells. From 20 to 70 tons of fine sand are removed

from the fluid treated each day, the amount of sand in the fluid returned to the wells being generally less than 2 per cent.

Circulating-system Operating Conditions.—Operating conditions that govern control of the circulating system vary widely. From a practical point of view, it will be of interest to determine the rate of circulation desirable for the drilling fluid and the pump delivery pressure necessary to achieve it. The ascending velocity necessary to lift drill cuttings and their elapsed time in passing from the bottom of the well to the surface will also be of interest. Use of from 100 to upward of 1,500 bbl. of fluid may be necessary to fill the well and mud ditch and sump, depending chiefly upon the depth and diameter of the well. As much as 860 gal. per min. are circulated in large-diameter holes to achieve the necessary ascending velocity, depending chiefly upon the cross section of the annular space between the drill pipe and the walls of the well. Ascending velocities range to upward of 200 ft. per min. Pump pressures necessary to offset drill-pipe and well friction at the necessary rates of flow, depend upon the flow cross section of the drill pipe and annular space, but roughly average 100 lb. per 1,000 ft. of depth.

Loss of drilling fluid to the formation will depend upon the permeability of the formations penetrated by the well, varying from a minimum of but a few barrels per hour in very "tight" formations to the full delivery capacity of the pump in very porous "thief" sands. Such loss must be made up by addition of water to the mud pit. Lost circulation may require adoption of suitable methods for closing the pores or crevices in the wall rocks through which the fluid escapes from the well. Clay deposited on the walls of the well must be replaced in the drilling fluid by addition of fresh hydrated clay in the mud pit. The amount of clay necessary increases directly as the diameter of the well and the thickness of mud cake deposited on the walls of the well. When, because of addition of clay from the formation penetrated by the well, the amount of solids in suspension is unduly increased, water must be added to maintain the proper fluid density and, with some types of clay, resort must be had to the use of chemical reagents to reduce the mud viscosity. If facilities for desanding the drilling fluid are inadequate and fine sand accumulates, it may be advisable to discard the fluid in use. If natural gas becomes entrained in the fluid to such an extent as seriously to reduce the mud density, it should be replaced with fresh fluid; otherwise there may be danger of a blowout resulting in violent ejection of fluid from the well. "Heaving" shales and fractured formations tending to cave into the well as it is drilled are serious problems in some fields and may require special attention to the properties of the drilling fluid. Salt water, entering the well from water-

yielding formations encountered in the course of drilling, may seriously alter the properties of the drilling fluid and perhaps require special chemical treatment. Unsuitable mud properties or inadequate ascending velocities may result in deposition of an unduly thick mud sheath on the wall of the well; or drill cuttings may accumulate in the circulating fluid in the bottom of the well to such an extent as to "freeze" the drill pipe or cause a twistoff.

FUNCTIONS OF THE CIRCULATING FLUID USED IN ROTARY DRILLING

In its flow through the circulating system, the drilling fluid has a variety of different functions to perform. It must carry all the drill cuttings from the bottom of the well to the surface and discharge them into the settling ditch or on the vibrating screen. Prompt and continuous removal of the material loosened by the drill prevents its accumulation in the well with the possibility of freezing the drill pipe. The drilling fluid must absorb heat generated in the drill pipe and bit by frictional contact on the walls and bottom of the well. To prevent caving, it must deposit a thin sheath of clay on the walls of the well, aided by the plastering action of the rotating drill pipe. The clay sheath so formed lubricates the drill pipe so that it rotates with less friction and power loss. The clay, thus deposited, must close the pores of formations yielding high-pressure gas or water that might prove troublesome or dangerous, and also seal unusually permeable low-pressure formations, fissures or crevices through which the fluid might be drained away in sufficient quantity to cause loss of circulation. The drilling fluid must have sufficient density to be capable of providing ample hydrostatic pressure to prevent high-pressure gas, oil or water from entering the well in such quantity as to cause a destructive blowout. The fluid must possess thixotropic properties so that, in the event of unexpected interruption in circulation, it will gel and prevent settling of drill cuttings to the bottom of the well.

To fulfill these requirements satisfactorily, the drilling fluid must be of suitable density and viscosity and must have well-developed colloidal properties. It must be free of sand and dissolved substances that might cause rapid flocculation, coagulation or settling of clay particles. In addition, the drilling fluid must not be so viscous as to create undue pump pressure or power loss in forcing it at a suitable rate through the well; and the density and viscosity must be such as will encourage separation of drill cuttings and entrained gas in the mud ditch or other facilities provided at the surface for their separation.

The properties desirable in a drilling fluid will vary from time to time as different conditions must be contended with in the drilling of the well. Normally, in routine drilling, a fluid weighing about 70 or 75 lb. per cu. ft.

(10 lb. per gal.) and having a viscosity of about 10 or 15 centipoises, with sufficient colloidal material to develop suitable wall-building properties, will be appropriate for circulating drill cuttings to the surface and maintaining the walls of the well in proper condition. If we wish to seal off a porous, low-pressure sand that is absorbing the well fluid, or wish to deposit clay rapidly on the walls of the well to combat caving tendencies, the amount of clay—particularly its colloidal content—should be temporarily increased. At such times, the density and viscosity will normally be increased but we may reduce the viscosity, if need be, by addition of appropriate chemical reagents. If high-pressure gas encountered in formations penetrated by the drill shows a tendency to enter the well, the density of the drilling fluid may temporarily be increased by addition of finely ground heavy minerals that do not increase the viscosity of the fluid unduly. "Gas-cut" drilling fluid, containing entrained gas bubbles, loses density rapidly as the gas bubbles expand on reduction of pressure, perhaps to such an extent as to permit a sudden flow of high-pressure gas to enter the well and violently eject the drilling fluid. Entrained gas is released with difficulty from highly viscous drilling fluid and viscosity-reducing chemical reagents may be added at such times. Again, when drilling in heaving shales, the circulating fluid may have to be chemically treated to prevent undue increase in viscosity and to improve the stability of the walls. Or sudden loss of circulation in an unusually permeable, low-pressure sand may necessitate addition of coagulants or flaky or fibrous materials to the drilling fluid.

Action of the Circulating Fluid in Removing Material Loosened by the Drill.—In raising drill cuttings from the bottom of the well to the surface, effective action of the drilling fluid depends chiefly upon maintenance of a proper fluid density and viscosity and a rate of flow that will maintain a suitable ascending velocity in the annular space between the drill pipe and the wall of the well. The size and density of the drill cuttings are also important factors. High density and viscosity of the circulating fluid and high ascending velocity tend toward effective removal of drill cuttings. Fine pulverizing of the drill cuttings also promotes lifting efficiency.

The circulating fluid, in rising from the bottom of the well to the surface, behaves as a great hydraulic classifier in its effect on drill cuttings suspended in it; and many of the principles apply that find application in the design and operation of hydraulic classifiers in ore-dressing operations. The circulating fluid is discharged from the drill pipe against the bottom of the well through apertures in the drill and is deflected upward, carrying the drill cuttings in suspension. The force developed by perhaps several hundred gallons of fluid per minute, jetted through relatively small holes in the bit only a few inches off bottom, is probably sufficient to keep the bottom of the well free of all but the coarser broken material. In unconsolidated and semiconsolidated formations, the force of these fluid jets assists the bit to some extent in excavating material. Owing to the rotation of the bit, the fluid rising off bottom through the annular space between the drill pipe and the wall of the well at first assumes a swirling, helical motion which further assists in lifting drill cuttings. The path of travel of the cuttings is longer because of this motion, and therefore less force is required than if they had to be lifted vertically.

The ascending velocity of the fluid keeps the drill cuttings moving toward the surface as long as circulation in sufficient volume is maintained. The suspended solid particles, under the influence of gravity, tend always to sink in the circulating fluid. Only by circulating a sufficient volume of fluid so that it rises in the annular space more rapidly than the particles sink may we bring the latter to the surface; and the ascending velocity of the suspended particles will be measured by the difference between the upward velocity of the fluid and the sinking velocity of the particles in the fluid. Small particles will rise more rapidly than large particles of the same density; and for particles of the same size, those having the lower specific gravity will have the greater ascending velocity. In other words, the circulating fluid exercises a selective action on the material loosened by the drill, and it is conceivable that at a certain rate of circulation, with particles of variable size and density, the coarser and heavier material might remain on bottom or in suspension in the well fluid, only the lighter, smaller particles reaching the surface. In time, the heavier and coarser material may accumulate in the well to such an extent that the drill pipe becomes "logy" and tends to freeze in the hole. The remedy is a more rapid ascending velocity of the fluid, which is achieved by circulating a larger volume of fluid through the well.

Solid particles in suspension in the drilling fluid sink less rapidly in fluids of high density than in fluids of lower density, the rate of sinking being directly proportional to the differential between the density of the fluid and that of the suspended particle. Solid particles also sink less rapidly through highly viscous fluids than through fluids of low viscosity. Resistance offered to relative motion of the solid particles and the fluid depends upon the interfacial friction between the liquid and the solid surfaces, and this is a function of the viscosity of the fluid. Some authorities have reasoned that Stokes' law should apply in computations of the rate of sinking of drill cuttings in drilling fluid, but this is doubtful for the reason that the amount of solid material in suspension in the fluid is such as to place the problem within the realm of "hindered settling," a condition which obeys quite different laws.

The more rapid the progress in drilling, the greater must be the speed of the pumps. This becomes apparent if we consider that energy proportional to the weight of the material broken by the bit must be expended in lifting it. For every foot of hole 10 in. in diameter drilled in average sedimentary rocks at a depth of 5,000 ft., we must do, theoretically, upward of 400,000 ft.-lb. of work in lifting the drill cuttings to the surface. Considering slippage or sinking of the solid material through the fluid on its way out, and the general inefficiency of application of energy in this method of lifting material, it is apparent that we must expend considerably more work than this. Obviously, at times when the drill is making hole more rapidly than usual, more energy will be required in lifting cuttings, and this is provided by operating the pump at higher speed and circulating a greater volume of fluid per unit of time.

Should circulation be interrupted, as will happen when the power fails or when it is necessary to withdraw the drill pipe from the well, coarse and dense material in suspension in the fluid in the well will at once begin to settle toward bottom, perhaps accumulating in sufficient quantity about the bit and drill collar to freeze it to the walls or make it difficult to reestablish circulation. As a safeguard against difficulty of this character, it is important that the drilling fluid be of such consistency as will prevent rapid settling of suspended solids. High viscosity is advantageous in holding solids in suspension. Well-developed colloidal properties also ensure a minimum rate of settling. Some clays have thixotropic tendencies so well developed that, within a short time after coming to rest, the fluid containing them gels—practically congealing—so that a permanent suspension of all solid particles results. Subsequent agitation, effected by restoration of circulation, will again convert the gelled clay to a fluid condition.

Action of the Circulating Fluid in Sealing Porous Formations and Wall Building.—The extent to which the circulating fluid will deposit clay on the walls of the well, and within the pore spaces and crevices of the wall rocks, depends upon the percentage of solids present in the fluid, upon its colloidal properties, the permeability of the wall rocks, the rate of flow and hydrostatic pressure in the well and within the formations exposed in the walls of the well. Heavily laden fluid of low colloidal value, sluggish in its flow, will deposit its clay on the walls of the well more rapidly than when there is comparatively little material of well-developed colloidal properties in suspension, or when a rapid rate of flow is maintained. Too rapid flow will erode away loosely consolidated material exposed in the walls. High differential pressure between the well and the surrounding formation encourages movement of fluid from the well into the formation, especially if the latter is highly permeable. The walls of the well thus serve as a filter bed upon the surface of which a mud cake is deposited. Fine particles of clay in suspension in the fluid enter and accumulate in crevices and pore spaces through which flow occurs, perhaps gelling in and eventually closing all openings through the wall rocks so that they become permanently sealed against movement of fluid either from or into the well. Smooth-surfaced walls offer less opportunity for clay deposition than do exposed surfaces that are irregular and rough.

A certain proportion of the clay in the circulating fluid tends to remain in permanent suspension, and this ordinarily will not be deposited. Any clay deposited on the walls of the well must be in addition to this. Accordingly, when it is particularly desired to deposit clay on the walls of the well, an extra amount is added to the fluid in the mud pit. Indeed, clay must be added continually to the circulating fluid if the mudding process is to be continued, for the fluid will soon drop its surplus clay and attain a condition of equilibrium. It should be noted that the volume of clay necessary to plaster the walls of the well will vary directly as the diameter of the hole. For example, the wall area exposed per foot of depth in a 12-in. hole is double that in a 6-in. hole. Deposition of mud on the walls of the well is greatly aided by the plastering action of the eccentrically revolving drill stem.

The amount of clay carried by the drilling fluid in the equilibrium condition varies with the nature of the clay (as explained above) and also with the rate of flow. The amount of clay that can be carried in suspension in the well fluid without deposition increases as the rate of flow increases. This, of course, is directly dependent upon the speed and capacity of the pumps and upon the cross-sectional area between the drill pipe and the walls of the well. It follows that if heavy deposition of clay is the object sought, the speed of the pumps must be reduced until a suitable rate of flow is attained. If a pump delivers 100 gal. of fluid per minute through a 6-in. drill pipe in a 10-in. hole, the rate of flow as the fluid ascends through the annular space will be about 44 ft. per min. With 4-in. drill pipe in a 7-in. hole and the same delivery capacity of the pump, the rate of flow will be about twice as great. And the fluid will carry more clay at the higher speed without deposition than at the lower. By varying the speed of the pumps, a nice adjustment of the rate of deposition to suit any condition is possible.

The extent to which clay penetrates the wall rocks varies with the permeability of the formation and the excess of pressure applied. In close-grained rocks, the clay deposit is probably almost entirely on the rock surface, but with the more permeable formations it seems reasonable to expect that it penetrates to a depth of several inches and this is confirmed by experimental research. In strata traversed by well-developed drainage channels, drilling fluid has, in some cases, appeared in wells several hundred feet distant from that into which it was pumped, proving that a considerable and fairly rapid migration through the more permeable strata is possible under favorable conditions. Loss of fluid during circulation is a direct measure of

the pressure conditions within and the permeability of the strata penetrated; and drillers customarily watch the depth of fluid in the mud pit as a measure of the nature of the formation in which the drill is working. In cases where low-pressure "thief" sands absorb drilling fluid so rapidly that circulation back to the surface cannot be maintained, drilling must cease until the highly permeable formations can be sealed off and circulation back to the surface restored. At such times, the fluid is loaded with fibrous or flaky materials and highly colloidal clay to promote gelling tendencies. If the condition persists, resort may be had to the use of cements, hydraulic lime, sodium aluminate or other chemical reagents that promote agglomeration of the clay particles.

Action of the Circulating Fluid in Controlling High-pressure Fluids Encountered in Formations Penetrated in Drilling.—Effective application of the circulating fluid in controlling high-pressure gas, oil and water encountered in drilling depends not only upon its ability to seal the pores of the rock, but also upon the opposing hydrostatic pressure that can be developed to prevent extraneous fluids from entering the well. Here density of the fluid is important, the hydrostatic head at any depth increasing directly with the specific gravity of the fluid. Drilling fluids weighing 70 or 75 lb. per cu. ft. will ordinarily be of sufficient density to control formation fluids, but at times when abnormally high fluid pressures are encountered, heavier drilling fluids must be employed. Finely ground heavy minerals added to the clay fluid will develop suspensions weighing as much as 150 lb. per cu. ft., yet without excessive viscosity. Ordinary clay-laden fluids become too viscous to be readily pumpable when the density exceeds about 85 lb. per cu. ft. (0.59 lb. per ft. of depth). Hydrostatic pressures of about 0.7 lb. per ft. of depth are the highest that have been found necessary in practice.

If a high-pressure gas-bearing horizon is being penetrated by the drill and there is not sufficient hydrostatic pressure developed in the well to offset the gas pressure, it will tend to enter the well and flow to the surface occluded in the drilling fluid. The gas exists in the form of finely divided bubbles that expand to form a froth as the fluid approaches and is discharged at the surface. Occasionally so much gas is entrained in the fluid that its density is seriously reduced. As a result, the differential pressure between the formation and the well is further increased and more gas enters, perhaps in sufficient quantity violently to expel the well fluid at the surface. "Gas-cut" fluid often does not readily release its gas in the mud ditch and storage pit at the surface, particularly if the fluid is highly viscous. If this is the case, the fluid must either be discarded or treated in some way to release the entrained gas. This may be accomplished by passing the fluid through a vibrating screen or by diluting with water, subsequently thickening the fluid to proper density after the gas is released. Gas reaching the surface in the drilling fluid does not necessarily indicate that insufficient pressure is being maintained to prevent the gas from entering the well from the formation. It may be merely such gas as is stored in the pores of the material pulverized by the drill. Though the volume of this gas in its place of storage is small, owing to its high pressure, it is capable of expansion to a volume sufficient to alter seriously the characteristics of the circulating fluid.

Action of the Circulating Fluid in Absorbing Heat and Lubricating the Drill Pipe.—When a steel bit is revolved against a rock surface with sufficient pressure literally to tear the rock apart, a great deal of energy is expended and, necessarily, heat is generated. Furthermore, this work is done in a confined space in a material having a temperature of 60 to 200°F. or more, so that there is little opportunity for natural conduction of heat away from the center of action. The greater the bit pressure and the more rapid the rate of drilling, the greater will be the heat generated. Were it not for the circulating fluid, the drill would in a few minutes become so hot as to suffer serious loss in its wear-resisting qualities. One of the important functions of the

circulating fluid is that of absorbing this heat and conducting it away. There is also considerable heat generated by stress in the drill pipe and by its continual frictional drag on the walls of the well. This heat, also, is absorbed by the circulating fluid.

The drilling fluid enters the well at about atmospheric temperature but quickly begins to absorb heat as it travels down through the drill pipe. The circulating system is like a great heat exchanger, the cool descending fluid within the drill pipe absorbing heat from the warm fluid ascending about it. The ascending fluid is heated not alone by absorption of heat from the drill pipe and bit, but also by absorption of formational heat. The important center of heat generation is, of course, reached at the drilling bit and, in order to bring the cooling fluid into close contact with the cutting edges, it is discharged through holes in the bit as near the cutting elements as possible. These holes are small in comparison with the cross section of the opening through the drill pipe; hence the flow velocity is greatly increased at this point. The fluid, under high pressure and moving with high velocity, is jetted directly against the bottom of the hole and deflected upward, assuming a swirling, helical motion that is quite effective in absorbing heat developed in the bit and drill pipe; but any interruption in circulation will quickly cause trouble if the bit is continued rotating on bottom.

Ability of the circulating fluid to absorb heat is determined by its specific heat, by the temperature at which it is supplied and by the weight of fluid circulated per unit of time. Pure water has a higher specific heat than clay; hence, we obtain maximum cooling effect with fluids containing small percentages of clay, supplied at low initial temperature and in large volume—*i.e.*, at high velocity.

The circulating fluid also has the duty of reducing the frictional drag of the drill pipe on the wall of the well. Smaller than the bore of the well, the drill pipe revolves eccentrically and is distorted by stress, so that it develops pressure contact with the walls of the well at many points. Were it not for the plastering action of the clay particles suspended in the drilling fluid and for the clay sheath deposited on the walls of the well, abrasion of the drill pipe would be rapid and a great deal more power would be consumed in its rotation. Although clays cannot strictly be said to possess lubricating qualities, yet because of the ease with which the clay particles shear and slide upon each other, they greatly reduce the sliding friction that would otherwise develop between the metal and rock surfaces. Some varieties of clay, such as bentonite, possess better lubricating properties than others. Presence of sand or gritty material in the drilling fluid, of course, reduces the lubricating value.

PROPERTIES OF CIRCULATING FLUIDS USED IN ROTARY DRILLING AND TEST METHODS EMPLOYED IN DETERMINING PROPERTIES

Among the properties of clay-laden fluids that are important in determining their performance as circulating fluids in rotary drilling, density, viscosity, colloidity, shear or gel strength, sand and salt content are important. Density of the drilling fluid is of significance in its function of lifting drill cuttings and offsetting high formation pressures. Viscosity of the fluid influences its fluidity and the frictional resistance offered by the circulating system to flow. Settling of sand and drill cuttings and release of entrained gas from the drilling fluid are also adversely influenced by high viscosity. Colloidal properties of the circulating fluid are important in determining its ability to form a mud sheath on the wall of the well, lubricate the drill pipe, prevent loss of fluid to the forma-

tion and restrict admission of formation fluids to the well. Gelling tendencies that help to maintain drill cuttings in suspension are also an expression of colloidity. The gel strength or shear value is a measure of the resistance offered to the settling of drill cuttings through the gelled fluid. Sand content is objectionable in a drilling fluid because of the tendency of the sand to scour the metal surfaces with which it comes into contact during circulation. Dissolved salt may alter the colloidal properties of a drilling fluid and render it unsuitable for use under certain conditions.

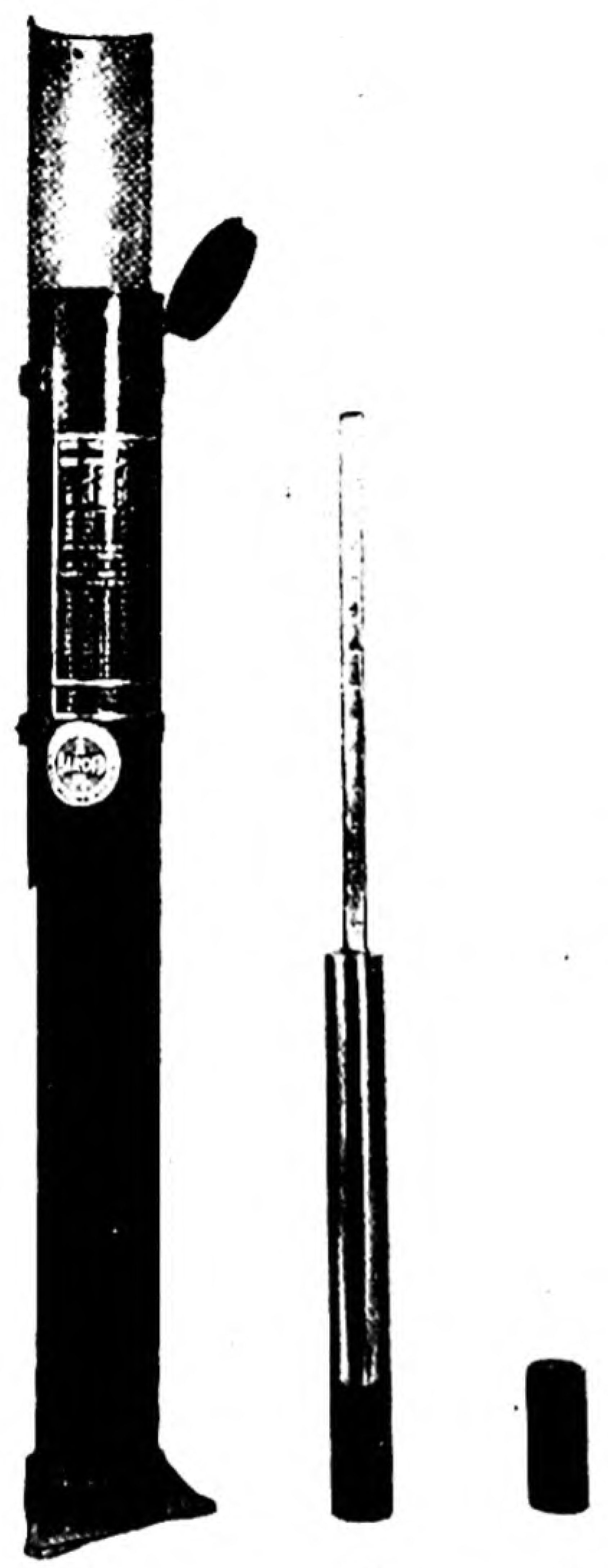
Density.—The density of a drilling fluid depends upon the amount and specific gravity of the suspended solids. Clay-laden fluids of density and viscosity suitable for rotary drilling purposes range in weight from 9 to 11.5 lb. per gal., or 67 to 86 lb. per cu. ft. Equivalent specific gravities are 1.08 to 1.38. The American Petroleum Institute recommends that mud weight be measured in a unit called "A.P.I. density," which is defined as the pressure developed by the fluid in pounds per square inch per hundred feet of depth. Table XXV gives equivalent values for the several different units in which mud density may be measured.

TABLE XXV.—A.P.I. DRILLING-FLUID DENSITIES AND EQUIVALENT UNITS

A.P.I. density	Specific gravity	Lb. per cu. ft.	Lb. per gal.
43.1	1.00	62.3	8.3
46.8	1.08	67.3	9.0
49.4	1.14	71.1	9.5
52.0	1.20	74.8	10.0
54.5	1.26	78.5	10.5
57.1	1.32	82.3	11.0
59.7	1.38	86.0	11.5
62.3	1.44	89.8	12.0
64.9	1.50	93.5	12.5
67.5	1.56	97.2	13.0
70.1	1.62	101.0	13.5
72.7	1.68	104.7	14.0
75.3	1.74	108.5	14.5
77.9	1.80	112.2	15.0
80.5	1.86	115.9	15.5
83.1	1.92	119.7	16.0
85.7	1.98	123.4	16.5
88.3	2.04	127.2	17.0
90.9	2.10	130.9	17.5
93.5	2.16	134.6	18.0
96.1	2.22	138.4	18.5
98.7	2.28	142.1	19.0
101.3	2.34	145.9	19.5

Muds weighing more than about 86 lb. per cu. ft. (59.7 A.P.I. density), if prepared exclusively with clay and water, are apt to be too viscous to be readily handled by the pumps, and gas and sand will not readily settle out. If heavier fluids are needed,

resort may be had to the use of finely ground heavy minerals, such as barite, hematite, pyrite or siderite, which contribute high density without corresponding increase in viscosity. With heavy minerals used in lieu of or in addition to clay in the drilling fluid, mixtures weighing as much as 150 lb. per cu. ft. (104 A.P.I. density) may be prepared that are not too viscous to be handled by the pumps.



(*Courtesy of Baroid Sales Division, National Lead Co.*)

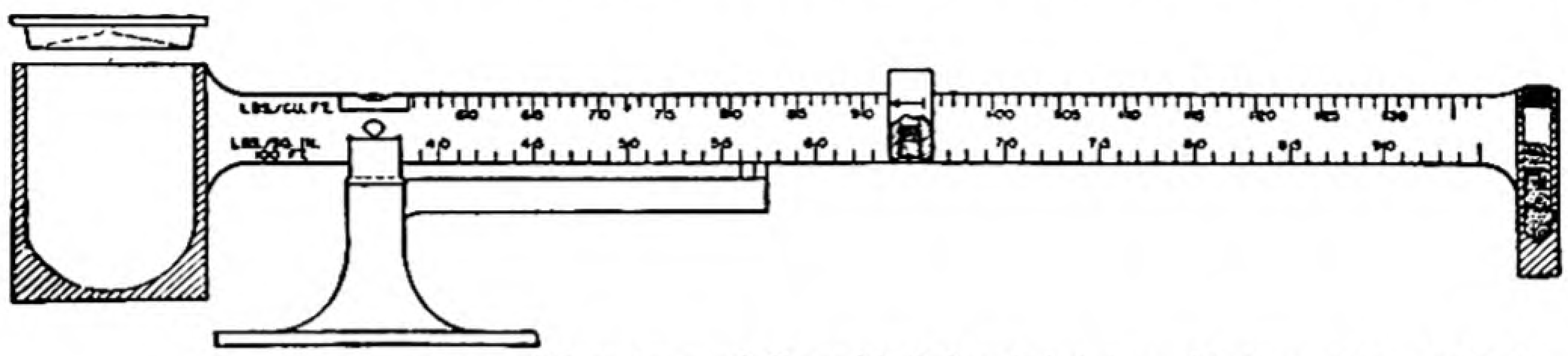
FIG. 111.—Mudwate hydrometer. *A*, water container and carrying case; *B*, assembled hydrometer; *C*, detachable bakelite cup.

Several instruments are available for determining mud density. A primitive method involves weighing a gallon of the drilling fluid in a tarred bucket with a spring balance. A more accurate device for this purpose is the Mudwate hydrometer illustrated in Fig. 111. The hydrometer, 26 in. in length, consists of a float spindle with calibrated stem, a detachable bakelite cup and metal-carrying case. In operation, the cup is detached from the float stem by a turn to the left and filled with the mud to be tested. The cup is replaced and excess mud clinging to the instrument wiped away. The carrying case is filled with water and the spindle floated therein. The density of the mud determines the depth to which the float stem sinks. The stem is calibrated to indicate mud density in A.P.I. density, pounds per cubic foot and pounds per gallon.

A less commonly used but convenient and entirely dependable instrument for determining mud density is the Baroid mud balance, illustrated in Fig. 112. It consists principally of a base and graduated beam with cup, lid, knife-edge, rider and counterweight. A constant-volume cup is affixed to one end of the graduated beam, which has an adjustable counterweight on the opposite end. The rider is partly filled with lead shot to provide the correct weight. A level bubble mounted on the beam gives rapid and accurate indication of balance. With the lid removed, the cup is filled with the mud sample to be tested. The lid is then placed in position and rotated until firmly seated, thus expelling the excess mud through a small hole in the center. Any mud adhering to the exterior of the instrument is washed or wiped off. The balance arm is placed on its base with the knife-edge resting on the fulcrum. The rider, adjusted on the beam until the instrument is in balance, indicates the mud weight in A.P.I. density and pounds per cubic foot.

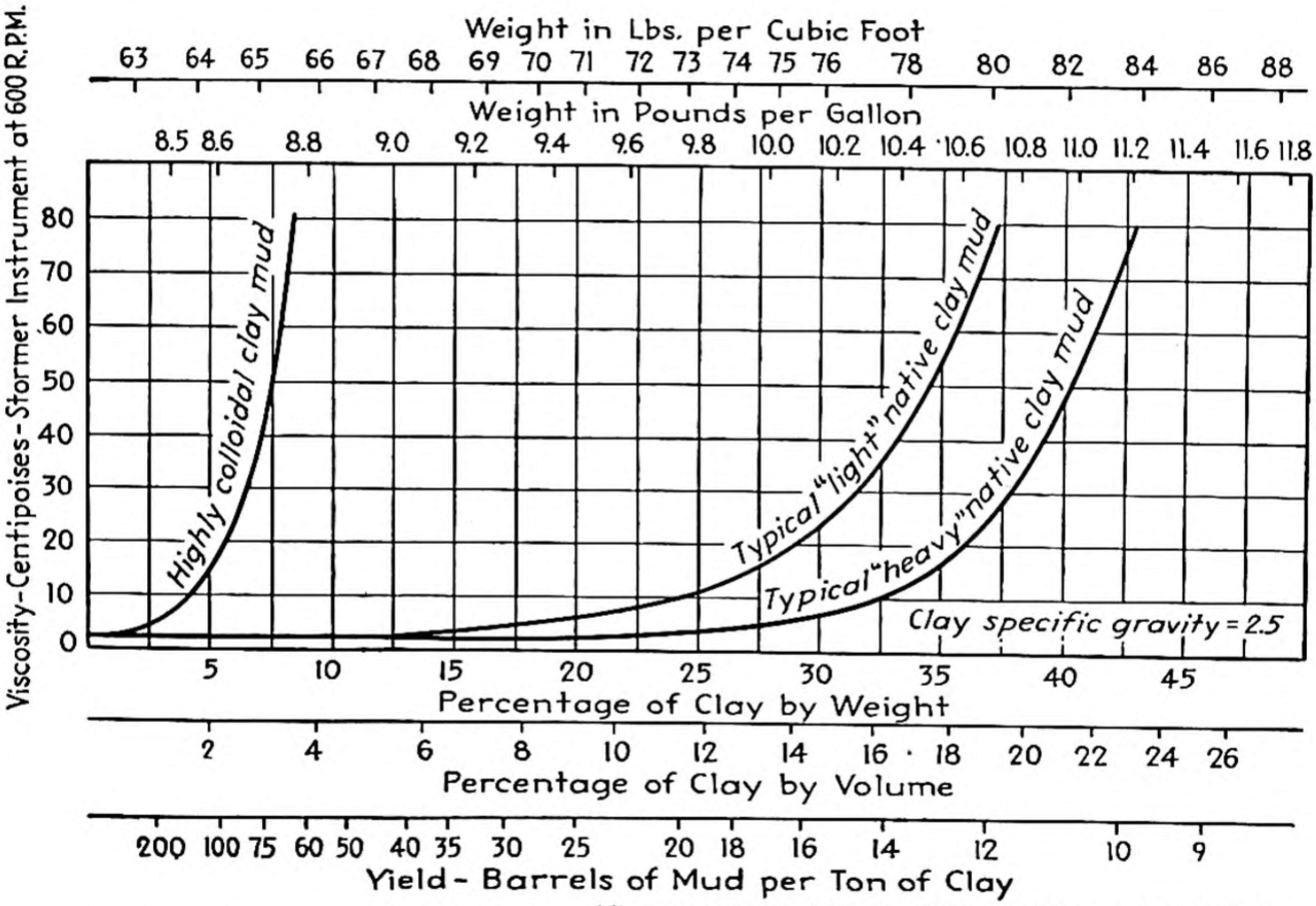
Viscosity.—The viscosity of a drilling fluid depends upon the amount and character of the suspended solids. In general, the greater the percentage of suspended solids, the greater will be the viscosity; and plastic solids like kaolin and bentonite develop higher viscosities than noncolloidal substances like silica, barite or hematite. A given percentage of bentonitic clay in suspension in water will develop a higher viscosity than does a like percentage of kaolin. Addition of deflocculating agents

such as tannin and sodium phosphate to a clay suspension will often produce marked reductions in viscoity. Generally, increase in alkalinity tends to increase viscosity and increasing temperature tends toward diminished viscosity. The graphs of Fig. 113 present results of tests to determine the influence of different factors on drilling-fluid viscosity. Drilling fluids that possess gelling tendencies increase their



(*Courtesy of Baroid Sales Division, National Lead Co.*)

Fig. 112.—Mud balance. Designed in compliance with A.P.I. specifications.



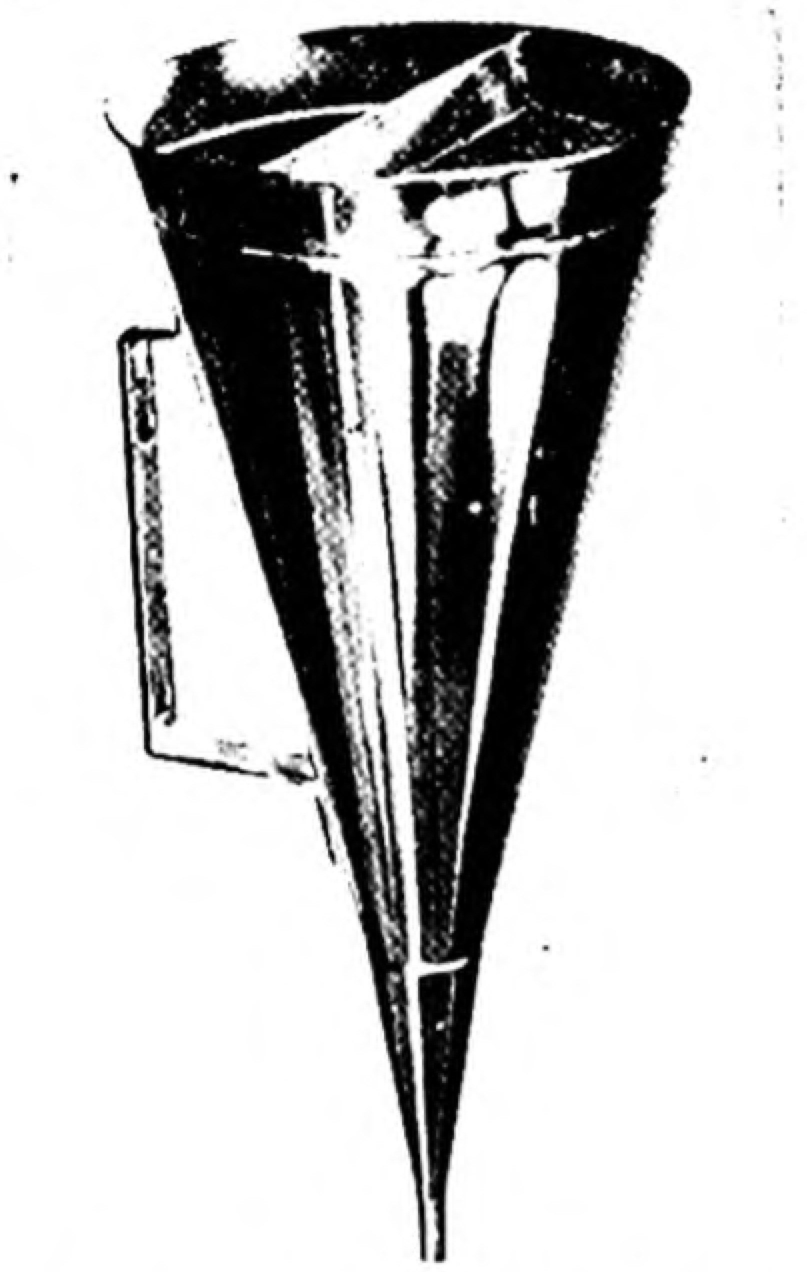
(*Courtesy of Baroid Sales Division, National Lead Co.*)

Fig. 113.—Graphs showing influence of clay content on viscosity of drilling fluids.

viscosity markedly after coming to rest for a time, in comparison with their viscosities while in fluid motion. Viscosities of drilling fluids may fluctuate over a wide range with variation in the factors mentioned, actual values varying from but a few centipoises to more than 300 centipoises.

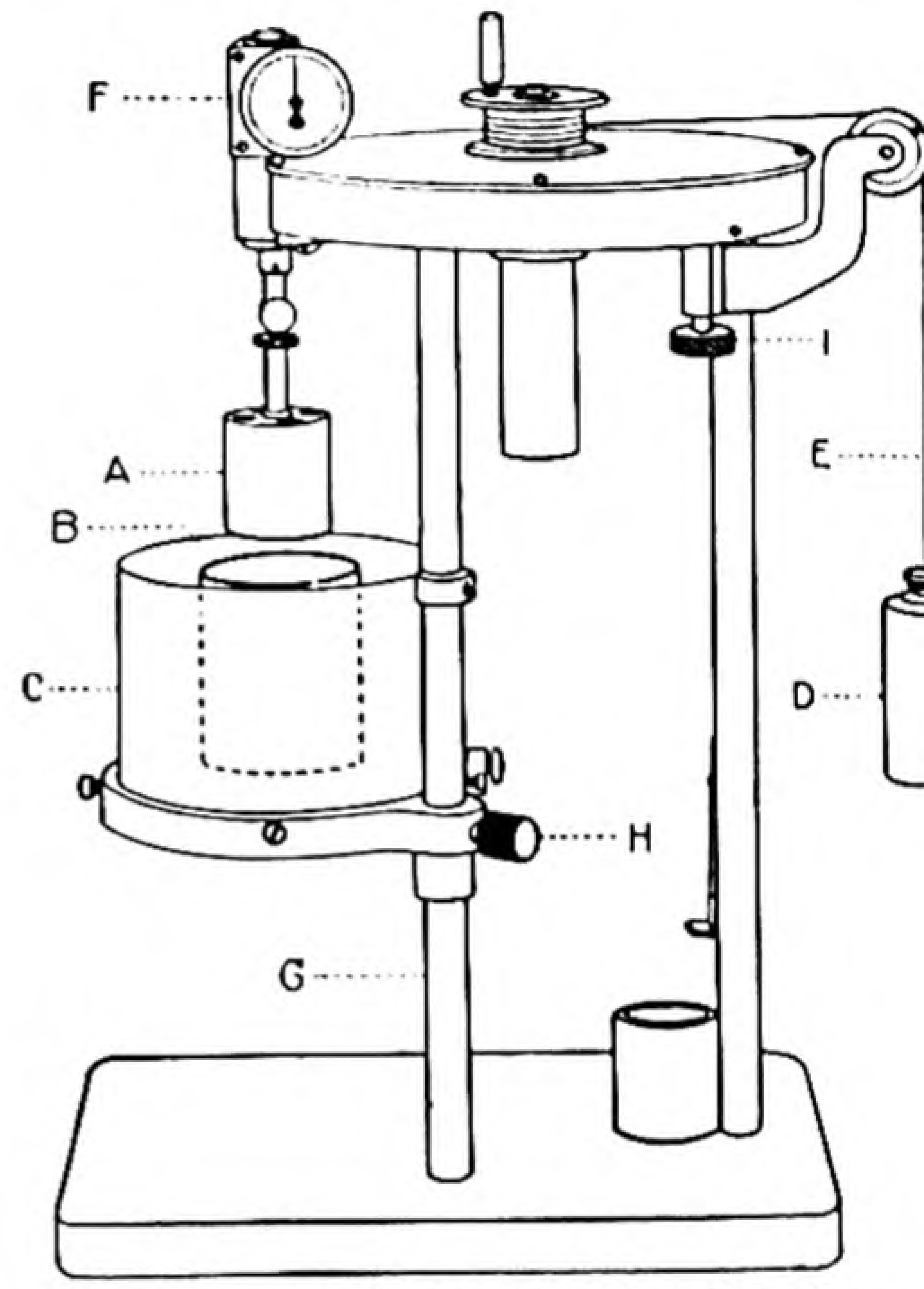
Several instruments are available for determining drilling-fluid viscosity, some being designed primarily for laboratory use, others being appropriate for field use. The most commonly employed instrument for determining relative viscosities of drilling fluids at the well is the Marsh funnel. As illustrated in Fig. 114, this is a cone-shaped funnel, constructed of rustproof metal, 6 in. in diameter at the top

and 12 in. long. The discharge tube at the bottom is bored accurately to an internal diameter of 3/16 in. An 8-mesh screen covering half of the large end of the cone is mounted in the bottom of a pan 1 in. deep. The funnel is equipped with a handle and is designed to be semipermanently mounted on a fixed support in a vertical position with the point of the funnel down. In use, the funnel is filled with the mud to be tested to the 1,500-cc. level, which is the level of the screen. (Use one finger to close the outlet tube.) With the finger released, the mud is allowed to flow out and the time of discharge of 1,000 cc. of the test fluid is measured by means of a calibrated receptacle and a stop watch. The indicated relative viscosity of the fluid is the time in seconds necessary to discharge 1,000 cc.



(Courtesy of Baroid Sales Division, National Lead Co.)

FIG. 114.—Marsh funnel for determining drilling fluid viscosity.



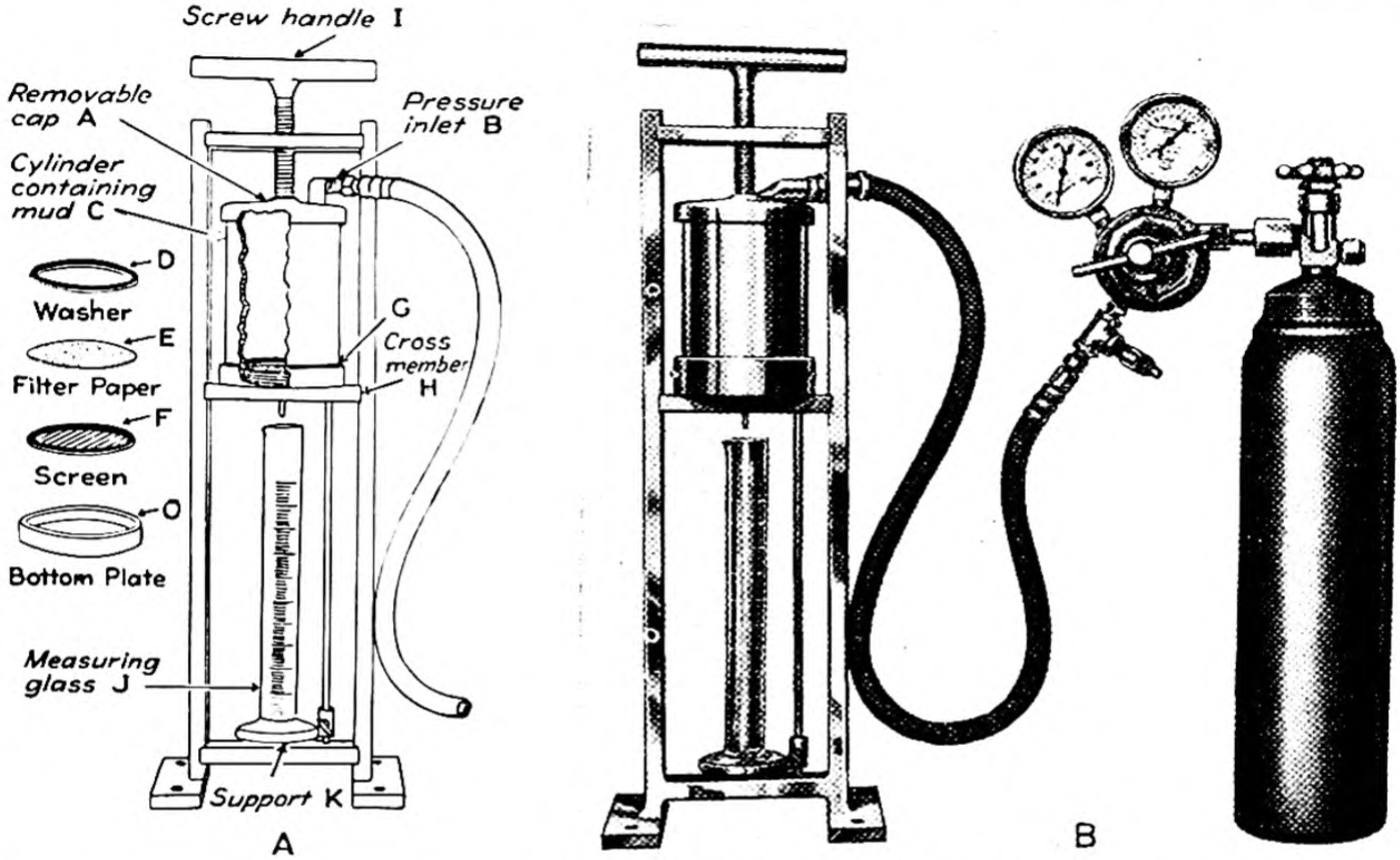
(Courtesy of Baroid Sales Division, National Lead Co.)

FIG. 115.—Stormer viscosimeter.

The Stormer viscosimeter illustrated in Fig. 115 is well adapted for determining drilling-fluid viscosity and gel strength. It is primarily an instrument for laboratory use, but can be taken into the field for use at the well if properly protected and cared for. The viscosimeter consists principally of a spindle *A* which is rotated in a test cup *B* by a pair of gears driven by a weight *D*, suspended on cord *E*. The rate of rotation is indicated by a revolution counter *F*. The drilling fluid to be tested, screened free of all material coarser than 80 mesh, is thoroughly agitated and immediately thereafter poured into the test cup *B*, filling the latter so that vanes on the inside surface are completely submerged. The cup is placed in the water bath *C*, which maintains proper temperature, and this entire assembly is raised to test position on the support rod *G* and held in position by tightening setscrew *H*. The spindle *A* is made free to rotate by releasing the brake screw *I*. The fluid in the test cup is agitated by revolving the spindle with the aid of the small crank on the cord-winding drum. The weight *D* is then adjusted until the spindle is made to revolve at a rate of shear of 600 r.p.m. as determined by the tachometer *F* and a stop watch. By means of a calibration chart accompanying each instrument, the weight in grams

required to achieve this rate of shear may be converted into centipoises. Readings are recorded in centipoises determined by the Stormer instrument at 600 r.p.m.

Other viscosimeters suitable for use in determining the viscosity of drilling fluid under laboratory conditions are the McMichael torsion viscosimeter and the egg-beater type of viscosimeter. The latter consists of a rotating spindle equipped with fixed paddles, mounted in a mud receptacle and operated by a small constant-speed electric motor. Suitably calibrated, an ammeter on the power circuit driving the motor may indicate the viscosity of the fluid in which the spindle revolves. A. D. Garrison and K. C. ten Brink have described an improved type of torsion viscosimeter



(*Courtesy of Baroid Sales Division, National Lead Co.*)

FIG. 116.—Baroid wall-building test instrument. *A*, sectional view showing filter arrangement; *B*, exterior view showing arrangements for pressure regulation.

useful in determinations of fluid viscosity under accurately controlled laboratory conditions.[27]

Colloidal Properties of Drilling Fluids.—The ability of a drilling fluid to form a suitable mud sheath on the wall of the well, to seal the pores of the wall rocks and to lubricate the drill pipe, depends upon its colloidal properties. Clay-laden fluids possess colloidal properties in varying degree, depending chiefly upon the characteristics of the clay used, but influenced also by the chemical constitution of the water phase. Bentonitic clays have colloidal properties more highly developed than most kaolinites, and a specially prepared bentonite marketed under the name of Aquagel is often added to drilling fluids deficient in colloidity.

There is no unit of colloidity and no method of measuring the colloidal value of a drilling fluid in a strictly quantitative sense. However, methods are available for indicating relative colloidal values of different fluids and of predicting their probable behavior in functions where colloidity is a controlling factor. The most direct method is that afforded by a wall-building test instrument. Here the ability of a fluid to form a mud cake, under conditions closely simulating those at depth in

an actual well, may be directly observed. An instrument especially designed for this purpose is illustrated in Fig. 116. It consists essentially of a filter cell and a device for applying pneumatic pressure to fluid enclosed within it. The test fluid is forced through a screen-supported filter paper on which the mud cake is formed. After a test the filter may be removed and the adherent mud cake examined. The thickness of the mud cake and the rate of filtration of water through it are taken as a measure of its effectiveness.

The hydrogen-ionization value (pH value*) of a clay suspension, or degree of acidity or alkalinity, is of interest as an index of colloidal value as well as other properties. Ability to retain clay in suspension in water, the viscosity, gel strength, corrosiveness and extent of gas adsorption are drilling-fluid properties that are related to the hydrogen-ion concentration. It may be measured in a comparative way and values expressed in terms of the pH (Sörensen) scale by either colorimetric or electrometric methods. Both methods have been approved by the A.P.I.

In the colorimetric method, as exemplified by the Wulff pH tester, strips of gelatin are impregnated with different dyes that assume either one of two colors or a blended intermediate tint when immersed in fluid of the pH value for which the dye is sensitive An indicator strip appropriate for the pH of the fluid to be tested is immersed in the fluid for one minute, withdrawn and wiped carefully and the resulting color is compared with a color scale on a standardized slide. Five different color standards are available. These, with their corresponding indicators, are capable of indicating the pH value of drilling fluids over a range of from 1.4 to 12.6 and it is possible to determine values within 0.2 pH.

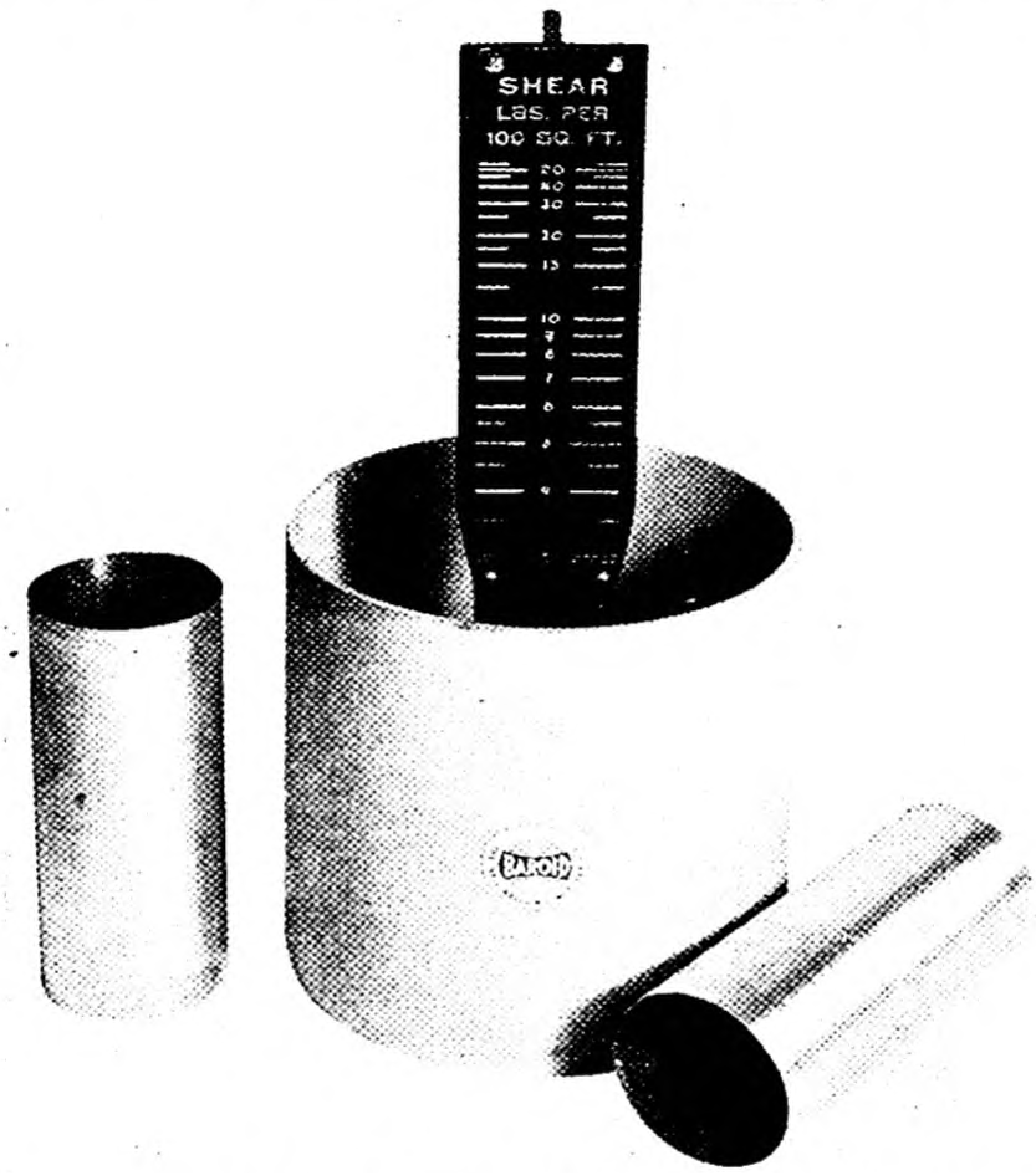
The electrometric method, as exemplified by the Beckman pH meter, involves generation of an electrical potential in a glass electrode system by the fluid under test. The electrical potential developed between two electrodes is amplified and the pH value is directly indicated on a sensitive millivoltmeter. Prior to a test, the instrument is adjusted with the aid of a standardized solution and the electrodes are then simply immersed in a beaker containing the fluid to be tested. A button is pressed, closing the electrical circuit, and the voltmeter needle at once swings to indicate the pH value on a reference scale. Readings are possible within 0.02 pH. The instrument is contained within a compact case and is readily transportable.

Thixotropic Properties.—The term "thixotropy" is applied to that property of a water suspension of clay which causes it to become a semisolid gel when it is left undisturbed for a time; the jellylike mass thus formed being readily disintegrated by agitation so that it again takes on the characteristics of a fluid. The apparent viscosity of a drilling fluid may thus vary over a wide range, depending upon the extent to which the latticelike coagulation of suspended clay particles forming the gel has advanced. A drilling fluid in rapid circulation through the well may have an apparent viscosity of only 20 centipoises. After a 10-min. period of quiescence, the same fluid may have an apparent viscosity of 1,000 centipoises or more. This is a valuable property in a drilling fluid for, by means of it, the suspended drill cuttings are prevented from settling in the well when circulation is interrupted. As long as the fluid is in motion, the gel strength or "shear value" remains low and the drill cuttings settle out readily in the mud ditch. But if, for any reason, the pumps are

* The pH value is defined as the negative logarithm, to the base 10, of the hydrogen-ion concentration expressed in moles per liter. Alkaline solutions have pH values ranging from just above 7, the neutral point, to slightly above 14, the strongest alkalinity; acid solutions range from just below 7 for slight acidity to about 0 for the strongest acidity.

stopped for a time, the fluid in the well increases its gel strength and the drill cuttings remain suspended.

Settling of drill cuttings is resisted by the gel strength or shear value of the fluid, a property which can be measured in a comparative way by either of several types of instruments. The simplest of these is the Marsh funnel, previously described. In using the Marsh funnel for measurement of gel strength, the time of efflux of the standard volume of the fluid is first determined promptly after thorough agitation. A second sample is then placed in the funnel and allowed to remain at rest for 10



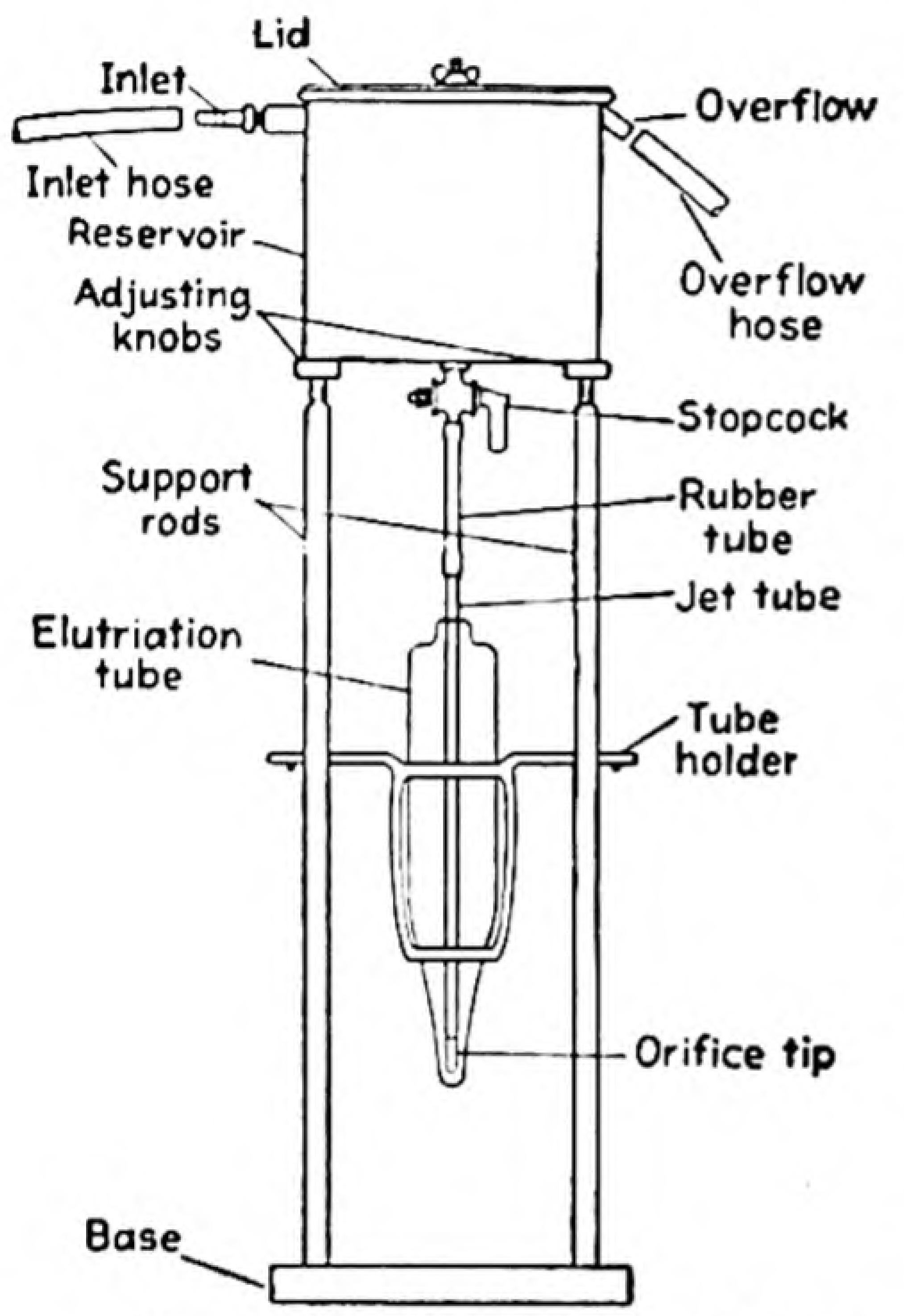
(*Courtesy of Baroid Sales Division, National Lead Co.*)
FIG. 117.—Shearometer.

min. before it is drained. The time of efflux after 10 min., less the time of efflux measured promptly after agitation, is called the "ten-minute Marsh gel strength."

The Stormer viscosimeter, described in an earlier section, may also be used for determination of relative gel strength of a clay suspension. The fluid sample is allowed to stand undisturbed in the cup of the instrument with the spindle immersed for 10 min., and weights are then gradually applied to the plumb line until the spindle starts to revolve. The weight necessary to start rotation of the spindle is a measure of the gel strength.

The Shearometer, adopted by an A.P.I. committee as a tentative standard instrument for determination of the shear value or gel strength of a drilling fluid, is pictured in Fig. 117. It consists of a thin-walled cylinder of duralumin, 3.5 in. long, 1.4 in. in internal diameter, weighing 5.0 grams. For fluids of very low shear value, a tube of the same proportions weighing only 2.5 grams is used. The Shearometer

cylinder is placed on a quiescent surface of the fluid and allowed to sink vertically until it comes to rest. After immersion, the tube is placed against the reference scale (see Fig. 117) and the point on the reference scale opposite the uppermost limit of the mud mark on the cylinder is taken as the gel strength. The scale is calibrated to read directly in pounds per 100 sq. ft. If a test is made immediately after thorough agitation of the fluid, the 5-gram Shearometer tube should immerse completely, indicating a gel strength of less than 3.0 lb. per 100 sq. ft. If the reading is above 3.0 lb., the gel strength is usually considered to be too high to permit sand and cuttings to settle out readily in the mud ditch and the pump pressure necessary to maintain proper circulation will be excessive. A test made on fluid that has remained quiescent for 10 min. may range in shear value from 7 to 20 lb. per 100 sq. ft., 15 lb. being a good average value.



(*Courtesy of Baroid Sales Division, National Lead Co.*)

FIG. 118.—Elutriator for sand tests of drilling fluids.

Sand Content.—The sand content of drilling fluid is detrimental from every point of view. If present in sufficient amount, it may freeze the drill pipe or drilling bit to the walls of the well, perhaps causing a twistoff. If casing is being lowered into the well through sand-laden fluid, it becomes logy and may not reach the intended setting depth. Sand in the drilling fluid is abrasive and may result in rapid scouring of pump liners, drill pipe, casing and other metallic equipment with which it comes into contact. Sand-laden fluid also has poor wall-building properties, developing a thick wall cake with consequent danger of interference with passage of tools and casing.

All material coarser than 200 mesh may be regarded as "sand" and good practice requires that the sand content of drilling fluid be maintained below 5 per cent. To determine whether or not the fluid meets this requirement, occasional tests for sand content should be made. Several test methods are employed, including elutriation, centrifuging, dilution and gravity settling, and sieve analysis. An A.P.I. committee recommends the elutriation method.[2] Figure 118 illustrates a simple type of elutriator that meets A.P.I. prescriptions. The principle applied in this device is one commonly used in ore-dressing operations. Water flowing upward at a fixed rate is able to lift suspended solid particles larger than a certain size, while coarser material is not raised. In Fig. 118, the water reservoir holds about 1 gal. A stopcock immediately beneath the reservoir controls flow of water from the reservoir. The rate of flow can also be adjusted by equal turns on the two adjusting knobs. A tube, partly of rubber, partly of metal, extends downward to a point near the bottom of the glass elutriation tube. Over-all dimensions of the apparatus are 8 in. wide by 28 in. high. In making a test, the water reservoir is filled with water and the incoming stream regulated so that a slight overflow is maintained through the overflow tube and hose throughout the test. With the stopcock underneath the reservoir closed, 75 cc. of the drilling fluid to be tested are poured into the elutriator tube and diluted with water to an approximate volume of 250 cc. The tube and its contents are thoroughly agitated and the glass tube and holder placed in position with the orifice tip of the jet tube ¼ in. from the bottom of the glass elutriation tube. The stopcock is opened to

allow water from the reservoir to flow slowly into the elutriation tube until all turbidity disappears and no additional solid particles can be flushed from the tube. The jet tube is then removed from the elutriator tube and the sand remaining in the elutriator tube is allowed to settle. The volume of sand accumulated in the bottom of the elutriator tube may then be read directly by reference to a graduated scale engraved thereon. For lightweight drilling fluids, the percentage of sand in the fluid may be estimated by assuming 1 per cent of bulk volume to be equivalent to 1.6 per cent by weight. Thus, a fluid with 5 per cent of sand by volume would contain 5×1.6, or 8 per cent of sand by weight.

Other methods of determining sand content of drilling fluid may be used if the elutriation apparatus is not available. A few minutes rotation of a sample of drilling fluid in a centrifuge will concentrate all sand in the bottom of the centrifuge tube, so that the volume may be estimated directly by reference to the tube graduations. A simple method consists of placing a measured amount of drilling fluid in a graduated glass sedimentation tube (or centrifuge tube), diluting with water, agitating and then allowing the tube to stand at rest for 20 or 30 sec., the time depending upon the size of the tube and the volume of sample taken for test. At the end of the allotted time, the volume of sand that has settled in the bottom of the tube is taken as the sand content. The sieve analysis method of sand determination involves passing a measured volume of drilling fluid through a small 200-mesh screen, washing away excess clay, gathering and weighing or determining the volume of the sand so segregated. After accumulating the sand by washing on the screen, it is turned upside down and the sand washed down with water through a funnel into a graduated tube where its volume may be measured.

Salt Content.—Contamination of drilling fluid with salt water may have serious consequences, perhaps causing flocculation of the clay particles and impairing their wall-building properties. The concentration of salt in a drilling fluid may be determined either by titration with a standardized silver nitrate solution to determine chloride content, or by measuring the electrical conductivity of the fluid. An electrical apparatus is available (see page 655) which continuously indicates the conductivity of the fluid flowing through the mud ditch. A sudden increase in conductivity is taken as evidence of contamination of the well fluid by salt water.

Mud-control Laboratories a Necessity.—Consideration of the nature of the tests employed in proper drilling-fluid control, and the character of equipment used, will suggest the need for well-equipped and conveniently situated field laboratories on properties where any considerable number of wells are to be drilled. Although some of the test equipment employed is rugged enough to permit of taking it into the field, for most of the tests the facilities of a laboratory will be desirable. Personnel employed in making such tests must be technically trained and skilled in the use of delicate equipment. A Mudwate hydrometer for determining density of drilling fluid and a Marsh funnel for determining viscosity are about the only instruments that one ordinarily finds at the well. Other equipment described is preferably kept in the field laboratory. In lieu of a field laboratory, some operators carry all of the necessary test equipment to the well in a small portable laboratory built into an automotive trailer which is left at the well for use whenever circumstances require (see page 651).

DRILLING-FLUID CONSTITUENTS AND THEIR PROPERTIES

In addition to clay and water, the principal constituents of nearly all drilling fluids, a variety of other materials may be used in developing certain properties. Finely ground heavy minerals may be added to confer high density; highly colloidal material may be added to increase thixotropic properties; chemical reagents may be added to control viscosity; and fibrous materials may be added to assist in sealing highly permeable formations. Rarely, oil-base fluids carrying carbon black in suspension are used in drilling in low-pressure reservoir rocks, rather than clay-laden water. The petroleum technologist should be familiar with the properties of these various constituents and with their influence on the performance of drilling fluids under different conditions.

Clays.—Clays are derived by a process of degradation and weathering, from various silicate igneous and metamorphic rocks. Chemically they are composed primarily of hydrated aluminum silicates of very small particle size but they vary in the percentage of silica, alumina and combined water, and various metallic oxides are usually present as impurities. They are therefore not to be regarded as minerals having a fixed chemical composition. Clays may be classified broadly into two groups: (1) the kaolinite group having the approximate formula $Al_2O.2SiO_2.2H_2O$; and (2) the montmorillonite group having the approximate formula $Al_2O_3.4SiO_2.H_2O$. When hydrated, clay particles are believed to arrange themselves in a laminar crystalline lattice in which alternate layers of aluminum and silicon atoms are bound together by oxygen bridges. Though very thin, the individual clay particles have great strength, forming rigid platelike particles with a very large ratio of length to thickness. When dry, the individual clay particles are bound closely together but, when hydrated, the water molecules migrate in between adjacent clay laminae and force them further apart so that the mixture assumes plasticity. When still further dispersed in water suspension, the individual clay particles display Brownian movement but, if the fluid gels, this motion ceases. The extent to which a clay expands or is dispersed on hydration depends upon its origin and upon the chemical and colloidal nature of other substances present. In nature, clays are always associated with various adsorbed cations, usually alkaline or alkaline earth cations that are readily replaceable by each other or by hydrogen; and these adsorbed substances have much to do with the properties and behavior of the clay.[60]

Kaolin, the most common variety of clay, contains a large percentage of inert material, and colloidal properties are not usually well developed though all clays contain more or less colloidal material. In a drilling fluid, kaolin is useful primarily in conferring weight and viscosity. The kaolin particles are comparatively coarse, upward of 90 per cent of the particles being of such size that they can readily be seen by the ordinary microscope.

Bentonite, one of the best known members of the montmorillonite group, has well-developed thixotropic properties. It is supposed to be an end product of the weathering of volcanic ash. The particle size is unusually small, being scarcely visible under the more powerful microscopes. These minute colloidal particles absorb water rapidly, seemingly expanding to many times their size when dry. Though present in small amount they are readily dispersible in water and yet may gel to form a cellular network which enmeshes relatively large amounts of water and gives some degree of rigidity to the fluid. When not gelled, they display a remarkable mobility and

carry strong negative electric charges on their relatively large surfaces: properties which enable them to remain afloat in water with little tendency to settle out or flocculate. Bentonite particles have highly developed the property of adsorbing water and ions of various substances with which they come into contact. They display the property of swelling on absorption of water in varying degrees, and the extent of expansion on hydration is regarded as an index of the value of the material for drilling purposes. A good bentonite will expand to from 20 to 40 times its dry volume on slow hydration.[17]

Kaolinite clays are plentiful in nature; bentonitic clays less so. When the clay used in a drilling operation is deficient in colloidal material and lacks thixotropic properties, controlled amounts of finely ground bentonite may be added to the drilling fluid to improve its quality.

Aquagel.—A specially processed bentonite, marketed under the name of Aquagel by the Baroid Sales Division of the National Lead Co., is widely used in preparation of drilling fluids in Western oil fields. A few per cent of Aquagel, added to a fluid made up of a suspension of colloidally inert material, will greatly improve its thixotropic and wall-building properties. Where high density in the drilling fluid is not essential, about 5 per cent of Aquagel mixed with water forms a fluid weighing 66 to 68 lb. per cu. ft. which deposits a thin, soft and water-impervious filter cake on the wall of the well which breaks away freely when the well is brought in. There is thus no tendency permanently to seal the pores of the wall rocks and adversely influence production. With ordinary clays, it is necessary to maintain a density of at least 75 lb. per cu. ft. and the clay may form a thick filter cake on the wall of the well, detrimental in subsequent drilling operations and perhaps adversely influencing the productivity of the well on completion.

Water.—The water used in preparing drilling fluid should be reasonably free of dissolved salts; otherwise the properties of the clay suspension might be altered. High chloride content, which would be characteristic of sea water and might result from contamination with ground waters or by penetrating soluble salt masses in the course of drilling, is particularly detrimental. Chlorides tend to flocculate the dispersed clay particles and may destroy the colloidal properties that are so essential in wall building and in sealing permeable formations. Occasionally, soluble salts in the clay used will enter into solution in the drilling fluid and influence colloidal properties. Alkaline salts are generally not objectionable in this connection.

Weighting Materials.—Heavy minerals are frequently added to drilling fluids to increase their density, thus rendering them better able to offset high gas, oil or water pressure. For this purpose, barite is widely used and iron oxide, galena and various other materials are also occasionally employed. Such materials must be finely ground, it being usual to pulverize them so that 90 per cent or more will pass a 200-mesh screen and a large percentage should pass 300 mesh.

Barite (barium sulphate) has a density of 4.2 and, by adding it in a finely ground condition to at least an equal volume of water, a fluid having an apparent specific gravity of as much as 2.4 may be produced (150 lb. per cu. ft.). Yet such a fluid may not have excessive viscosity and is readily pumpable. A small amount of colloidal material must be added to keep the solids in suspension. Baroid, a specially processed ground barite to which about 5 per cent of Aquagel has been added, is marketed by the Baroid Sales Division of the National Lead Co., and is widely used in Western fields as a weighting material.

Iron oxide (hematite) has also been extensively used as a weighting material. Though of higher density than barite (5.2), it is otherwise less desirable. Iron oxide prepared by roasting pyrites has been available on the market under the trade name of Colox, but soluble sulphates in such material are said to be troublesome. Finely

ground and roasted naturally occurring iron minerals, such as hematite, limonite and siderite, may also be used. Field workers prefer barite to iron oxide because reddish-brown stains left on hands and clothing are difficult to remove.

Finely divided silica silt produced from natural deposits in some localities has a specific gravity of 2.6 and, though considerably less dense than barite or iron oxide, it may be added to a thin clay suspension in quantities sufficient to increase the fluid density to as much as 1.7 (105 lb. per cu. ft.) without exceeding the allowable viscosity. Drilling fluid containing silica silt has less satisfactory wall-building and pore-sealing ability than fluid containing barite, but in localities where it is produced it is less expensive.

Lead sulphide (galena) has a specific gravity in excess of 7 and, when finely ground, may be added to clay suspensions to produce pumpable fluids weighing as much as 150 lb. per cu. ft. (sp. gr. 2.4). The material is too expensive for general use, but it has been suggested that moderate amounts might be employed in conjunction with barite or hematite and clay to produce fluids somewhat heavier than would otherwise be possible. Sulphide minerals produce drilling fluids that are readily "gas-cut," an important deterrent to their practical use.

Chemical Reagents Employed in Control of Viscosity and Colloidal Properties of Drilling Fluids.—Various chemical reagents are found to be effective in altering the physical properties of clay suspensions in water and have been widely used in the control of drilling fluid viscosity. Deflocculating or dispersing agents, such as tannin and certain phosphates, are used to reduce the viscosity of drilling fluids that are too heavily loaded with colloidal material. Other phosphates have the reverse effect, tending to flocculate clay suspensions and increase drilling-fluid viscosity. Various forms of tannin or gallic acid, neutralized with caustic soda (sodium tannate), have been widely employed in treatment of drilling fluids to reduce viscosity. Quebracho and other tree-bark extracts that are common sources of tannin are effective mud thinners and are available at reasonable cost. Among the many different forms of sodium phosphate, the orthophosphates (Na_3PO_4, Na_2HPO_4 and NaH_2PO_4) are flocculating agents, tending to coagulate the suspended clay particles, thereby increasing drilling-fluid viscosity. The pyrophosphates ($Na_4P_2O_7$ and $Na_2H_2P_2O_7$), metaphosphate $(NaPO_3)_6$ and tetraphosphate ($Na_6P_4O_{13}$) are deflocculants, tending to disperse colloidal suspensions of clay.

The viscosity of drilling fluid may be greatly increased by the addition of hydrated lime, $Ca(OH)_2$. Mud treated with this material is sometimes used in drilling the first few hundred feet of a well where the hydrostatic head of fluid is insufficient to form a proper filter cake on the wall of the well.

Sodium carbonate is sometimes added to drilling fluid to increase its alkalinity. Under some conditions, it may increase the fluid viscosity. Sodium bicarbonate is sometimes used to flocculate and restore the colloidal properties of drilling fluid that has become contaminated with cement. Sodium silicate is ordinarily a flocculating agent, but in small concentrations often has the reverse effect. It also contributes alkaline properties necessary in adjusting pH values. In highly saline clay-water suspensions, sodium silicate provides a degree of protection against flocculation of clay that is helpful in drilling through heaving shales. Ground barite suspended in a strong magnesium chloride brine also forms a low-viscosity heavy fluid useful in drilling in heaving shales.

Finely ground limestone or dolomite is occasionally added to drilling fluids where it is intended subsequently to treat the well with acid to remove the mud sheath. The acid attacks the limestone, thus disintegrating the deposited clay. This method is particularly helpful in developing production from low-pressure reservoir rocks.

Oil-base Muds.—In low-pressure reservoir rocks where the mud sheath formed on

the wall of the well is not readily displaced by subsequent flow of gas and oil into the wells, some operators use an oil-base drilling fluid instead of a water suspension of clay. Crude petroleum or diesel oil may be used and, to provide material for wall building, carbon black may be added. The density of such a fluid is, of course, much lower than that of water-base clay fluids. For heavier oil-base fluids, it has been suggested that finely ground magnesium oxide or carbonate be used as the suspended solid.

Materials Added to Drilling Fluids to Seal Unusually Permeable, Cavernous or Fractured Formations.—"Thief" formations that are responsible for excessive fluid loss in a drilling operation, perhaps even to the extent of making circulation of drill cuttings to the surface difficult or impossible, may be sealed by addition of various fibrous or flaky materials to the drilling fluid. For this purpose, straw, beet-pulp refuse from sugar-extraction plants and cotton-seed hulls have been used. Specially prepared fibrous materials containing asbestos fibers (Fibrotex) or mica are available on the market. Bentonite (Aquagel) added to neat cement is also helpful in difficult cases of "lost circulation." An organic colloid marketed under the name of Impermex, when added to drilling fluids in appropriate amounts, is helpful in reducing water loss to permeable formations to a minimum. Impermex-treated drilling fluid has a high pH value, high viscosity yet low shear value, and gelling tendencies are reduced. It is especially helpful in drilling through caving formations and producing zones with minimum water loss, and is also advantageous in obtaining cores and making formation tests with minimum drilling-fluid contamination. It is also useful in correcting detrimental influences developed by contamination of drilling fluid with salt water. As much as 24 lb. of Impermex for each barrel of fluid is sometimes necessary to realize fully these advantages.

Conditioning Drilling Fluids to Contend with Special Situations Presented in Rotary Drilling.—At times, conditions may develop in the drilling of a well that make continuance of operations difficult or dangerous. Often such conditions may be corrected by prompt adjustment of the physical properties of the drilling fluid. In drilling through a formation containing high-pressure gas, the circulating fluid may become gas-cut (*i.e.*, containing entrained gas in the form of small bubbles) to such an extent that its density is unduly reduced and a blowout may result. This condition usually develops because the fluid is too viscous to release the entrained gas during its flow through the mud ditch and pit. The remedy indicated is to add a viscosity-reducing agent, such as sodium tannate or sodium pyro-, meta- or tetra-phosphate. The situation may also call for prompt addition of a heavy mineral, such as ground barite, to add density to the fluid and reduce the danger of a blowout.

Again, the drilling fluid may become laden with fine sand that does not readily settle out in passing through the surface facilities. In this case also, the trouble may be traced to excessive viscosity and the remedy may be a thinner such as those mentioned above; or mere dilution with water will perhaps correct the difficulty if the resulting loss of density would not be dangerous. If so, the reduced density is corrected at

once by thickening or by the addition of inert solid material that will not add unduly to the fluid viscosity.

Oil-base Drilling Fluids.—In drilling through low-pressure reservoir rocks where the mud sheath formed on the wall of the well would not readily be displaced by subsequent flow of gas and oil, or where perforations in liners might become clogged with clay or production impaired by getting the walls of the well wet with water, some operators use an oil-base drilling fluid instead of a water suspension of clay. Oil-base muds are also helpful in drilling through materials such as heaving shale or salt, where the presence of water would be undesirable, and for taking cores under circumstances where contamination with drilling water would be undesirable.

Crude petroleum, diesel oil or stove distillate may be used as the liquid medium in oil-base drilling fluids, while lamp black is added to give gel strength and wall-building properties, and finely ground oyster shells, limestone or barite may be used to increase density. Blown asphalt may also be added to confer plastering properties. Fluids ranging in density up to 95 lb. or more per cubic foot may be developed by this means and the viscosity may be varied over a wide range.

Oil-base muds are inflammable and, when in use, precautions should be taken to minimize the fire hazard. They have little tendency to gas-cut and hence fluids of high viscosity may be used when drilling in gas-bearing formations. Although the cost of oil-base muds is materially higher than that of water-base fluids, avoidance of waste may reduce the cost to reasonable levels. After use in drilling one well, the fluid may be stored for use in another. Liners with smaller clearance may be set when oil-base drilling fluid is used because a very thin filter cake is deposited on the walls of the well. A number of patents have been issued covering the preparation and use of oil-base drilling fluids (see U. S. Patent 2,220,681).

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CHAPTER IX

ROTARY DRILLING PRACTICES

Preceding chapters have described in some detail the equipment employed in the modern rotary drilling rig. Being now familiar with the essential parts of the equipment, their functions and interrelations, we are in a position to consider the methods employed in operating the rig and the practices followed in drilling by the rotary system.

The Rotary Drilling Crew.—The crew employed in operating a rotary rig usually consists of five men: the driller and four assistants. The driller is in charge of operations and personally manipulates the principal mechanical controls at all times. He is assisted by two floormen, a derrick man and a boilerman (for a steam-powered rig). The last-named has immediate responsibility in operation and control of the boilers and incidental steam-generating and -transmission equipment. He also assists on the derrick floor in coupling or uncoupling drill pipe and casing, and in other ways when the services of an extra man are required. The floormen manipulate tongs and drill-pipe "stands" when running in or coming out of the hole with the drill column and, at other times, maintain and lubricate the mechanical equipment, prepare and condition the drilling-fluid supply and perform other routine duties about the rig. The derrick man is stationed up in the derrick at the level of the upper end of the stands of drill pipe. He latches and unlatches the elevators and assists in "stacking" and making up the drill column; also, he lubricates the hoisting gear and assists in routine maintenance duties at other times. The normal crew may be augmented with additional men at certain times when extra help is required; for example, when casing or cementing operations are in progress. The 8-hr. day is almost universal throughout the American oil fields; hence these three 5-man crews maintain operations at each drilling well on a 24-hr. basis. The work is divided into periods of drilling or "making hole," adding new pipe to the drill column, removing and reinserting drill pipe to change bits, and occasional interruptions in the normal routine to "run" casing, cement casing, make surveys and formation tests, take cores, and "fish" for broken or detached parts of the drilling equipment.

Starting the Well.—Let us assume that a steam-powered rig is to be used; that the equipment has been completely assembled and made

ready for operation, and a short conductor pipe set vertically under the center of the derrick at the spot selected for the well. With drilling fluid in the slush pit, steam in the boiler and all in readiness for drilling, a bit of the size selected for the initial well diameter is securely screwed to a short drill collar, and the latter is coupled to the lower end of the grief stem. To the upper end the rotary swivel is connected and this, in turn, is suspended from the hook of the traveling block (see Fig. 91). If a long drill collar is used, it may not be possible to use the grief stem until the well attains a depth somewhat greater than the length of the bit and collar. In this case, the drill column may be rotated by attaching a set of grip rings, on the rotary table, capable of gripping and rotating the cylindrical collar; or the drilling bit may be attached directly to the lower end of the grief stem. The bit, collar and stem, connected as described, are then lowered through the rotary table into the conductor pipe, until the bit is within a foot or so of the point at which excavation is to begin. Lowering the drill column is accomplished by partly releasing the hoisting drum brake, then clamping the brake so that the drum may not turn when the drilling bit has reached the desired position. The driving bushings are then inserted in the rotary table, one of the pumps is started, and the table clutch is thrown into operating position. As the drill column revolves, the hoisting drum brake is again released and the drill column lowered until the bit begins to cut into the material on bottom. The drilling fluid soon returns to the surface through the annular space about the drill column, and overflows into the mud ditch, which returns it to the slush pit after the drill cuttings have settled out.

Adding a New Length of Drill Stem.—At intervals of 20 to 40 ft., as the hole is deepened, it will be necessary to add a joint of drill pipe to the stem. The slush pumps are stopped, the table clutch is thrown out of gear, the driving bushings are removed from the table and the stem is raised by applying power to the hoisting drum. As the joint at the lower end of the grief stem emerges above the table top, the drill-pipe slips are placed in the table opening about the pipe and the stem is lowered slightly until the slips take hold. The table is then locked so that it cannot revolve, and the pipe tongs are applied above the joint, aided by a jerk line from one of the cat-heads on the draw works. When the joint has been loosened with the aid of the power, it can be unscrewed by hand, the three floormen of the crew grouping themselves about the stem and passing the tongs rapidly from one to another until the threads are disengaged. The grief stem and swivel are then hoisted until clear of the lower portion of the joint, then lowered and stood on end in one corner of the derrick, or lowered into a "rat hole" made by rotating two joints of 8-in. pipe under the derrick floor. The hook is then disengaged from the swivel bail and the casing elevators placed on the hook in its stead. Meanwhile, a joint of drill pipe has been brought into the derrick from the pipe rack with the aid of a casing carriage. The elevators are lowered, clamped under the collar on one end of the joint and the joint is raised until it hangs vertically in the derrick. After removing the protecting collar on the new joint of pipe, and "doping" the threads thoroughly, it is carefully lowered

into the open collar of the portion of the stem supported by the slips in the table. Tongs are then applied to the new joint, first by hand methods and finally with the aid of the power, connecting a jerk line from the handle of the tongs to one of the catheads on the draw works. When the new joint has been securely attached in this manner, the weight of the stem is transferred from the table to the crown block by hoisting the stem for a short distance and removing the slips. The stem is then lowered until the collar of the new joint is about 2 ft. above the table. The slips are again placed in position, and the stem lowered until the slips take hold. The elevators are then disengaged and removed from the hoisting-block hook, before engaging the bail of the swivel. If the hook is a large one, the elevators may be left on the hook. The swivel and grief stem are then raised until clear of the derrick floor, swung to the center of the derrick and, after doping the joint, gently lowered until the lower end enters the collar on the upper end of the new section of drill pipe. Application of the tongs and slightly raising the stem until the slips can be removed from the table complete the work. The pumps are then started, the stem is lowered until the bit is a few inches off bottom, the drilling bushings are placed back in the table and drilling is resumed. This procedure is followed with each joint of pipe added to the stem, except that at every third or fourth joint (depending upon the height of the derrick and the preference of the driller) a tool joint is used instead of the usual pipe coupling.

Replacing a Dulled Bit.—When slow progress indicates that the bit has become dull, the entire stem must be withdrawn from the well and unscrewed into "thrible" or "fourble" stands of three or four joints, respectively; that is, the stem is broken at each tool joint. The pumps are shut down, the rotary table disengaged from the power and the tools hoisted until the joint at the lower end of the grief stem emerges above the table. This joint is unscrewed by application of the tongs as described above, the swivel and grief stem placed in one corner of the derrick or in the "rat hole" and the elevators substituted for the swivel on the hoisting-block hook. The elevators are next lowered until they can be clamped under the tool joint on the upper end of the stem projecting above the table. The stem is then hoisted in the derrick until three or four joints of pipe have passed the table and the next tool joint emerges. The slips are dropped into place around the stem, the latter is lowered slightly until the slips take hold, the table is locked and the tool joint is broken. The disconnected section of drill stem, now suspended on the elevators, is swung over into one corner of the derrick and lowered until the lower end rests on the derrick floor. Meanwhile the derrick man has been sent up into the derrick and has taken his place on the thrible board or fourble board (depending upon whether three- or four-joint stands are in use), which places him at an elevation level with the top of the stand. The derrick man guides the upper end of the stand into its position of rest against the finger board and disengages the elevators. The elevators are then lowered, a hold taken under the tool joint on the upper end of the next stand and the process is repeated until the entire stem is disconnected and the bit emerges from the well.

With a skilled rotary crew, this work of drawing out and uncoupling the stem proceeds with clocklike precision. Each of the five men constituting the crew has a definite part to perform. The driller controls the engine and the draw-works clutches and brake. Three of his helpers work on the derrick floor about the rotary table, manipulating the pipe tongs, elevators and slips, and swinging the lower end of the stands to their position at one side of the derrick. The part of the derrick man has already been described. As much as 1,000 ft. per hr. of 6-in. drill stem, connected in three-joint stands, can readily be withdrawn and uncoupled in the manner described, or at the rate of one stand every 3 min. A skilled crew can uncou-

ple drill stem even more rapidly than this for short periods of time, but the work is tiring and fraught with some danger to the crew and to the equipment unless carefully performed. Hence undue haste is not encouraged.

When the bit emerges from the well, the table bushings must also be removed and, while out of their usual position, the opening through the table should be covered to prevent anything from falling through. The possibility of the bit dropping through the table opening as it is unscrewed from the drill collar must be guarded against particularly. After unscrewing the bit from the collar, a sharpened and properly gauged bit is substituted, and the new bit must then be lowered to bottom by coupling the sections of drill stem together again, a process precisely the reverse of that outlined above for withdrawing it. Each joint is doped before the stands are coupled together.

Mechanical Action of the Rotary Bit.—As the bit revolves on the formation in the bottom of the well, its effect will vary with the amount of pressure applied. If there is insufficient pressure on the bit, it will slide or drag over the rock surface, loosening grains or fragments of material only occasionally, so that progress will be slow; the bit will be rapidly dulled and will lose its gauge. If, on the other hand, too much pressure is applied, the bit will embed itself in the rock to such a depth that it cannot cut itself free and will chatter up and down as it revolves. Excess of pressure on the bit throws so severe a strain on the equipment at such times that breakage of the bit or a twistoff of the drill stem is very likely to occur. Furthermore, the hole is apt to be crooked. With the proper bit pressure the tool is forced to embed itself in the formation just enough to permit of its chipping away the rock in small fragments as the stem revolves. Under such conditions there will be a minimum of grinding action and the maximum footage, will be obtained.

In order that a rotary bit may make progress in advancing the depth of a hole, it must first achieve a certain degree of penetration. This is accomplished as a result of the pressure applied on the drilling tool by the heavy drill column, the amount of penetration increasing with the weight allowed to rest on the bit. An important factor influencing penetration is also found in the shape and size of the cutting edges presented to the formation by the bit. A tool presenting a thin edge, or a number of slender prongs of relatively small cross section, will be forced farther into the formation with a given bit pressure, than one presenting a broad, flat face of large area. The hardness and density of the material in the bottom of the hole determine the resistance offered to penetration and displacement.

Having penetrated the formation, the bit disintegrates the rocky material immediately in the path of the cutting edges or teeth by its axial rotation. This involves a certain degree of shearing or cutting action, which is resisted by the cohesion and elasticity of the rocky material. Generally, the greater the penetration, the coarser will be

the fragments broken from the formation. The penetration of the bit and speed of rotation must not be greater than the available power will justify, or such as will create a stress in excess of that which may safely be imposed on the drill column.

The bit finds relief from excessive penetration by vertical movement, made possible by the elastic deflection of the drill column. The column chatters up and down, and as a result the bit develops a certain degree of impact action that is effective in crushing the formation. Such action, however, has a destructive effect, tending to cause breakage of the bit and twisting off of the drill column.

The work done in pulverizing rock is a function of the reduction in diameter of fragments attained. The area of fractured surface created by action of the bit is, in some degree, a measure of the energy expended. It is doubtless more efficient, insofar as disintegration of the formation is concerned, so to control the operation of the bit as to produce coarse rather than fine particles. The advantage so gained, however, is partly or perhaps completely offset by the greater expenditure of energy required to lift the coarser particles to the surface through the medium of the circulating fluid. It seems probable that for a given type of material and for a given density and viscosity of the circulating fluid, there is a certain size of particle which represents the most efficient size from the standpoint of total power expended. Breaking the material to either coarser or finer size will occasion increase in power consumption.

In addition to its function of pulverizing the formation in its path, the drill must also assist in bringing the cuttings into suspension in the well fluid. The bit must not break material faster than the circulating fluid can carry it away. Mixing the cuttings with fluid must be so thorough that the tendency of the coarse particles to float or remain in a stationary position in the ascending well fluid is reduced to a minimum. Coarse particles so retained in suspension in the well fluid are a potential cause of "frozen" pipe, by settling about the lower end of the drill column in the event that circulation is interrupted.

The clearance spaces about the bit, through which the circulating fluid and entrained cuttings must rise toward the surface, should be of such cross-sectional area as will assure a proper ascending velocity. This, of course, depends also upon the volume of fluid circulated per unit of time. Among other factors, the lifting capacity of the circulating fluid for rock fragments depends upon its flow velocity. The ascending velocity of the fluid about the bit should be no greater than at higher levels. There is thus no tendency for the fluid to lift broken material off bottom until it is fine enough to be swept at uniform speed to the surface. Material too coarse for the fluid to lift will be left on bottom until it is crushed to smaller size by the bit.

Mechanical Action of the Drill Column.—As the well deepens, the ratio of the length of the drill column to its diameter increases. In a deep well, the length of the column may be many hundreds or even thousands of times its diameter. This long, slender column is capable of considerable elastic deformation between the rotary table at the surface and the bit at the bottom of the well. Doubtless, it acquires many degrees of torsional twist in normal operation, the amount of twisting and torsional strain varying with the bit pressure applied, the length of the column, the penetration of the bit and breakout resistance offered by the formation. In operation, the lower part of the drill column is normally under compression, since it must provide downward pressure on the bit. The downward pressure applied may at times, aggregate many thousands of pounds: so great a load that the drill column incurs considerable deflection, which is necessarily greater near the bottom where the greater compressive stress is attained. The pipe is deflected to develop pressure contact with the walls of the well, in extreme cases probably forming a position like a corkscrew in the hole for hundreds of feet above the bit. This flexible corkscrew is revolved with rapid variation in stress as the bit alternately digs into the formation and breaks free. There is doubtless considerable "whipping" of the pipe from side to side in the hole. Its eccentric motion is complicated by the vertical movement of the helical segments of the column as the bit pressure and torsional and bending stresses vary within wide limits. When the drilling bit must jump to free itself from excessive penetration, severe impact stresses are developed.

In deep drilling, the upper part of the drill column is under tension, for at least a part of its total weight must be suspended from the swivel. It therefore functions as a column under torsion and tension and hence its behavior is quite unlike that of the lower portion of the column which, as explained above, functions as a distorted column under torsion and compression. It is clear that there must be some neutral position in the drill column at which there will be only the torsional stress developed by rotation.

The stresses developed in the drill column are occasionally sufficient to cause its failure. Twistoffs are usually in the lower part of the column, near the bit, where the maximum bending and compression stresses occur. It is believed that metal fatigue and impact stresses, occasioned by vibration and jumping to gain relief from excessive penetration, play an important role in causing twistoffs of the drill column. These stresses are accentuated by excessive rotational speeds. Studies of the stresses developed in a column of drill pipe, in their relation to the torque applied by the rotary table, have shown that comparatively few twistoffs are due to torsional strain, there being normally a safety factor of from 1.5 to 9.

In earlier years, twistoffs of the drill column were very common. In drilling 246,000 ft. of hole, one California oil company recorded a total of 568 twistoffs, or an average of 2.3 per 1,000 ft. of hole drilled. This difficulty has been greatly reduced in modern rotary drilling practice by using tool joints of improved design and better materials, and by increasing the length and weight of drill collars. By making the drill collar sufficiently heavy to provide all the weight necessary on the bit, the portion of the drill column subjected to compression is confined to the drill collar, and this is made heavy and strong enough to withstand the maximum stress imposed. This practice also results in less deflection of the drill column, producing straight holes.

Metal fatigue, occasioned by repeated stress and deflection in the drill column, is doubtless the immediate cause of most failures. To minimize this hazard, some operators discard drill pipe after a certain amount of use. Opinions differ concerning the amount of hole that a column of drill pipe should make before being discarded. Obviously, this depends largely upon the character of use ond the care with which the pipe is handled. Individual strings of drill pipe may at times yield footages in excess of 50,000 ft. without excessive breakage. One California operator reports that 1 ft. of pipe should drill 5 ft. of hole, or in other words, that a string of pipe should be capable of drilling five wells. Deterioration of drill pipe by metal fatigue can be offset to a certain degree by special heat-treatment. The results are somewhat uncertain and individual joints respond to the normalizing treatment in varying degree. Many operators believe that in view of the lack of dependability of reconditioned pipe, the cost of such work is better applied toward purchase of new pipe.

Rotational Speeds.—The action of the bit and the stress in the drill pipe are directly influenced by the speed of rotation of the table. The rapidity of rotation must be proportioned to the bit pressure and penetration. All these variables must be adjusted to accord with the character of formation in which the bit is operating. Rotational speeds may vary from as little as 40 to upward of 500 r.p.m. In some fields, operators believe that a speed of 60 r.p.m. should not be exceeded. On the other hand, some operators have found that speeds as great as 400 r.p.m. are possible without unreasonable operational hazards, and with much more rapid progress than is possible at lower speeds. Greater rotational speeds have been made possible within recent years, by improvement in the quality of steel used in manufacturing drill pipe, improvement in construction and design of tool joints and bits, better control of bit pressure, and the practice of using longer and heavier drill collars.

The rotational speed that will be most effective and that will be feasible for the equipment provided must be determined primarily by

consideration of the character of formation in which the bit is operating. The type and size of the bit and drill pipe and drill collar, the bit pressure that it is proposed to apply and the volume and pressure of fluid that may be circulated by the pumps are also important factors. The skill of the driller in handling the equipment will also be an important consideration. One manufacturer of rock bits states that for hard formations and with a weight imposed upon the bit equivalent to from 2,000 to 2,500 lb. per in. of bit diameter, rotational speeds of 60 to 80 r.p.m. will give best results. In the hard formations of the west Texas, New Mexico, Oklahoma and Kansas fields, one operator has used table speeds of 100 r.p.m. or less with 9⅞-in. rock bits, using 10,000 to 15,000 lb. of bit pressure. Increasing the rotational speed to from 150 to 200 r.p.m. and increasing the bit pressure to from 14,000 to 19,000 lb. gave more rapid penetration but drill-column failures occurred much more frequently. In the softer formations of the California fields, higher rotational speeds with reduced bit pressures have been found advantageous. Using rock bits, it has been found possible, with modern equipment, to employ rotational speeds of 300 r.p.m. or more. If bit pressures and volumes of circulating fluid are suitably adjusted, the rate of penetration within certain limits is found to be proportional to the rotating speed. Failures of the drill column at these higher speeds are apparently no more frequent than at lower speeds, except in formations that cause excessive vibration and bouncing of the drill column. However, high rotational speeds are possible only when the compressive stresses are carried by a long and heavy drill collar and the drill pipe is entirely in tension. Generally speaking, fishtail and other drag bits should be operated with lower table speeds than rock bits.

The speed of rotation of the drill column is conveniently indicated or recorded by a table tachometer. This device comprises a small d-c generator equipped with permanent magnets. The voltage developed by this type of generator is always directly proportional to its speed. The generator may be belt-driven from the rotary table pinion shaft or from the shaft on the draw works which transmits the drive to the table. A voltmeter, suitably calibrated, indicates the rotational speed at all times; or, if desired, a recording instrument may be used which will provide a continuous record of rotational speeds of the table. Such a record, studied in relation to similar records of bit pressure, table torque and drilling-fluid pressure and rate of flow, provides a useful means of correlating the controllable mechanical variables with rate of penetration of the bit. The most advantageous conditions for drilling through different types of formations and at different depths may thus be prescribed. Causes of crooked holes, twistoffs of the drill column and other drilling difficulties may be determined by this means.

Bit Pressure.—The most effective bit pressure will vary with the character of the rock and the size and design of the bit, the harder rocks and larger bits requiring heavier pressures. If there is insufficient pressure imposed on the bit, it will slide or drag over the rock surfaces, loosening fragments of material only occasionally, so that progress will be slow; the bit will be dulled quickly and will lose its gauge. If, on the other hand, too much pressure is applied, the bit will embed itself in the rock to such a depth that it cannot cut itself free, and will chatter up and down as it revolves. Excessive pressure on the bit and resulting vibration throw so severe a strain on the equipment that breakage of the bit or a twistoff of the drill column is very likely to occur. Furthermore, the hole is apt to be crooked. With proper pressure on the bit, the tool is forced to embed itself in the formation just enough to permit it to chip away the rock in small fragments as the drill column revolves. Under such conditions, there will be a minimum of grinding action and the maximum footage will be obtained.

In some formations, such as limestone developing angular fractures, salt, very hard sandstones or quartzites and igneous rocks, the rate of penetration of the bit appears to increase as a straight-line function with increase in bit pressure, irrespective of the rotating speed and volume of fluid circulated. In other formations, such as soft sandstones, sandy shales and silts, the rate of penetration increases directly with weight on the bit if fluid volumes circulated and rotating speeds are proportionately adjusted. In still other types of formations, such as brittle shales, gumbos and conchoidal-fracturing limestones, there is a definite upper limit to the bit pressure that can be used efficiently, above which the rate of penetration will actually decrease.

To avoid subjecting the drill pipe to compressive stress with resulting fatigue failure, the weight on the bit should never be permitted to exceed that of the drill collar and, for safety, should normally be not more than half of this. Thus, all compressive stress is confined to the heavy drill collar. To provide sufficient weight in the drill collar for deep drilling, it must be at least 40 ft. long and occasionally as much as 360 ft. long (four stands). If excessive bit pressure is applied, so that deflection of the drill column occurs, the well is apt to depart from the vertical. Especially is this true in steep-dipping formations.

Bit pressures may conveniently be expressed in pounds per inch of diameter of the bit and, on this basis, values of from 300 to 2,500 lb. per in. are commonly employed for the sizes of bits in normal use, or an aggregate pressure from 1,000 lb. to 25 tons. Seldom however, is more than 10 tons advisable or necessary. Somewhat higher bit pressure may safely be used on rock bits than on drag bits. A committee representative of a large group of Mid-Continent operators assembled the

data of Table XXVI, which presents what are said to be average table speeds and bit pressures employed by operators in the Texas, Louisiana and Arkansas fields. The bit pressures are expressed in pounds pressure per inch of diameter of the hole. A study of bit pressure, in its relation to cutting speed in one of the Oklahoma fields, indicates an almost constant increase in cutting speed proportional to the increase in weight employed (see Table XXVII). At pressures above 41,000 lb., the 6-in. drill pipe used failed frequently. One successful California operator considers it good practice to use bit pressures of not more than 8,000 lb.

TABLE XXVI.—TABLE SPEEDS AND BIT PRESSURES USED IN ROTARY DRILLING*

Fluid volume, gal. per min.	Table speed, r.p.m.	Weight on bit, tons	Bit size, in.	Ft. per hr.
580	75	4	9⅞	31.0
580	75	4	9⅞	33.3
580	75	4	9⅞	30.0
580	85	4	9⅞	44.5
580	85	4	9⅞	42.5
580	85	4	9⅞	43.0
580	85	4	9⅞	46.0
580	90	4½	9⅞	49.5
580	90	4½	9⅞	52.0
550	90	3¾	8⅝	50.5
550	90	3	8⅝	44.3
550	100	5	8⅝	55.4
550	100	4	8⅝	63.5
550	100	5	8⅝	62.5

* After J. E. Brantly and E. H. Clayton in "Drilling and Production Practice, 1939," American Petroleum Institute.

TABLE XXVII.—INFLUENCE OF BIT PRESSURE ON CUTTING SPEED IN DIFFERENT TYPES OF ROCKS*

Weight on bit, lb.	Formation				
	Lime, ft. per hr.	Sand, ft. per hr.	Sandy lime, ft. per hr.	Shale, ft. per hr.	Sticky shale, ft. per hr.
23,000	1.9	....	....	2.94	2.47
26,000	2.5	4.0	....	2.95	3.23
29,000	3.4	3.04	....	2.97	2.80
32,000	3.78	5.24	....	3.72	2.38
35,000	3.9	4.76	3.03	4.19	3.7
38,000	3.0	4.14	3.85	4.13	4.44
41,000	4.1	4.05	4.99	3.94	3.5

* After R. S. Cartwright, "Petroleum Development and Technology, 1928–1929," p. 20, Am. Inst. Mining Met. Eng.

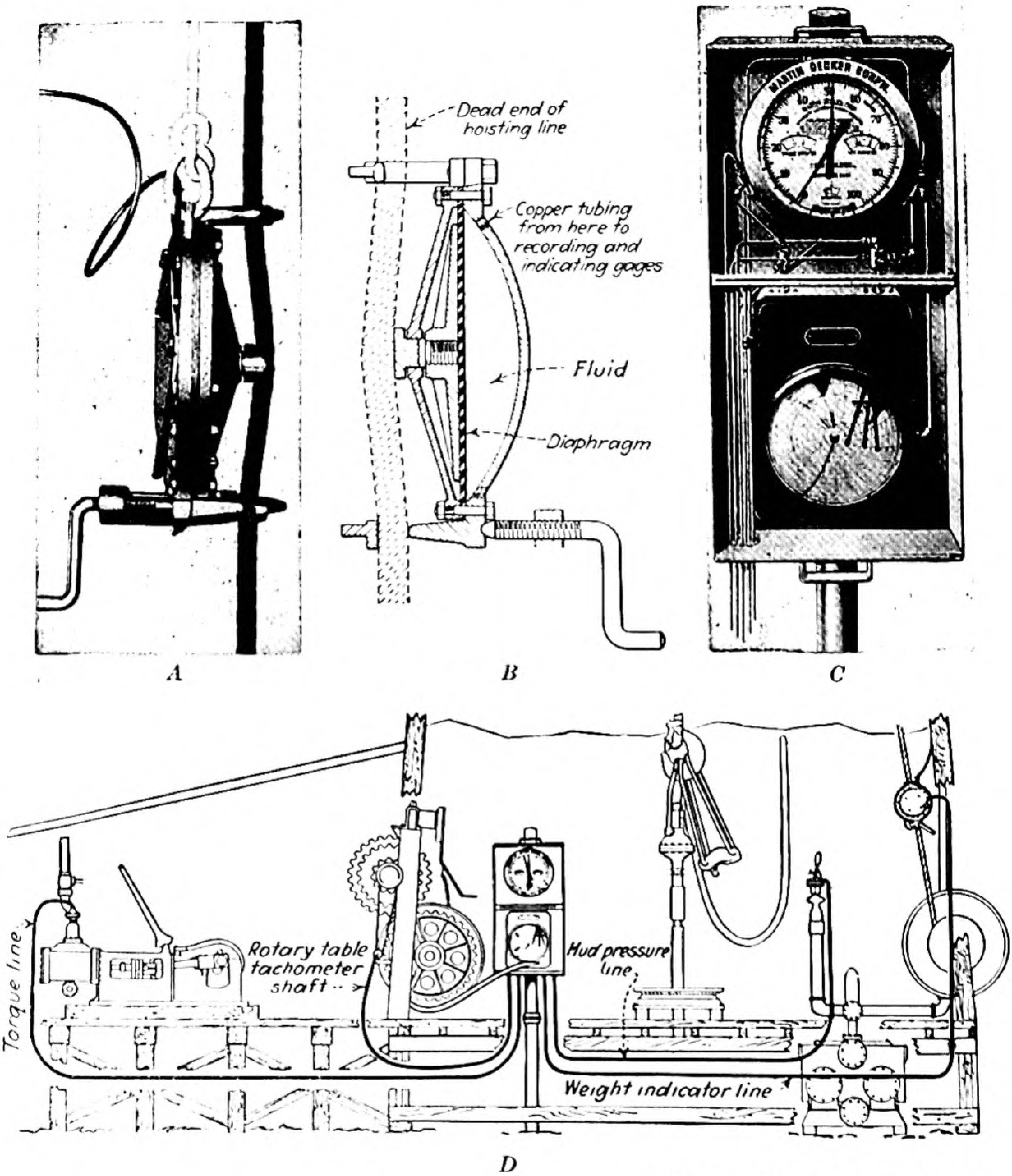
while drilling in soft shales and unconsolidated formations with fishtail bits, and from this up to 12,000 lb. when drilling in harder formations.

Weight Indicators.—When it is considered that the total weight of the drill column in a deep well may be 100 tons or more, and that only a few thousand pounds may be desired on the bit, it is apparent that a sensitive hand on the draw-works brake lever is necessary to bring about a proper distribution of load; good judgment in engine speed is equally important. Without auxiliary aids, the driller can only guess at the amount of pressure on the bit and must base his control of the apparatus largely upon what his experience has taught him is proper for the particular type of rock in which the bit is working, and for the depth and size of hole being drilled. He is able to form some opinion of the working pressure on the bit by the action of the drill column and by the resistance to his downward pressure on the hoisting-drum brake lever. He must adjust the speed of the engine to accord with the pressure applied and with the size of bit used: a large bit under heavy pressure requires slow speeds; with a small bit under comparatively little pressure, a rapid rotation of the drill column produces best results.

To aid the driller in maintaining proper bit pressure, several different types of weight indicators have been developed. One of these that has been used more than any other—and that has become almost standard equipment in the modern rotary rig—is the Martin-Decker weight indicator, illustrated in Fig. 119. This device indicates, on a pressure gauge, the tension in the hosting cable, which is a function of the bit pressure. The "dead line" of the hosting cable, attached either to the derrick sills or the shaft of a calf wheel or the hoisting drum of an auxiliary draw works, supports the weight indicator. The instrument is clamped on the cable in such a way as to form a kink in the line, which tends to pull straight under load. In so doing, it exerts a mechanical pressure proportional to the load against a diaphragm. This pressure on the diaphragm develops hydrostatic pressure on a fluid which communicates through tubing with the pressure gauge, placed in a position convenient for the driller's observation as he stands at his control post at the side of the draw works. The indicator hand on the pressure gauge, responsive to the pressure of the connecting fluid, indicates by reference to a circular scale on the gauge dial the number of "points" of bit pressure. Each unit of pressure registered on the gauge represents a certain tension in the hoisting cable, and the gauge reading in "points" may, by reference to a table or by simple calculations involving the number of lines supporting the traveling block and the weight of drill column in use, become a measure of the weight bearing on the bit. By observing the weight registered when the bit is just off bottom and again when it is in operation on bottom, the weight bearing on the bit can quickly be computed. Variations in size of the hoisting cable, buoyancy of the drilling fluid, irregularities in loading on the different lines supporting the traveling block, and friction of the drill column on the walls of the well will occasion some inaccuracy in estimates of bit pressure based on observations with this instrument, but for most purposes in the routine of drilling, the degree of accuracy afforded is sufficient.

Other types of weight indicators are available. The Ideal-Hill hydraulic weight indicator is designed as a part of the linkage between the traveling block and the rotary hook or connector which supports the swivel and elevators (see Fig. 120). It consists essentially of a cylinder which is attached to the traveling block and a piston which

is attached to the hook. Pressure between these two elements, created by the weight of the drill column, is transmitted to oil, with which the cylinder is filled, and the oil pressure is transmitted through a small flexible armored hose and pipe line to a system

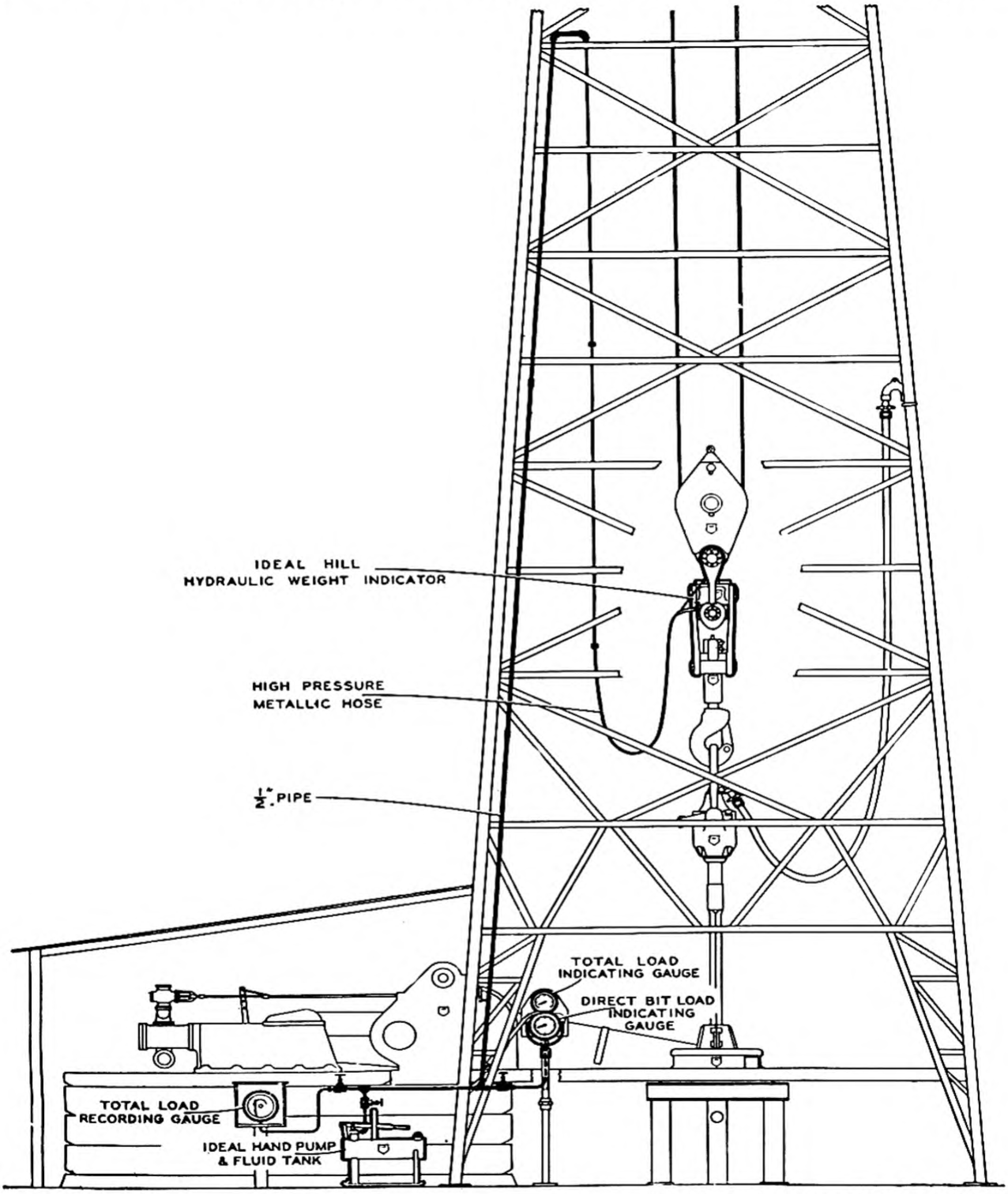


(*Courtesy of Martin-Decker Corp.*)

FIG. 119. Martin-Decker weight indicator and quintuplex drilling control instrument. *A*, side view and *B*, sectional view of Martin-Decker weight indicator; *C*, Martin-Decker instrument indicating weight on bit, torque on drill pipe, speed of rotation of rotary table and pump pressure; also gauge showing continuous record of drill-pipe weight and torque and mud-pump pressure; *D*, sketch showing connections for drilling control instruments.

of gauges mounted in a metal cabinet near the driller's position on the derrick floor. One gauge shows the total weight on the hook, on a scale reading directly in tons. Another gauge indicates weight bearing on the bit, in tons, and a recording gauge

makes a permanent continuous record showing all variations in the hook load. A small tank for storage of surplus oil is also provided, and a hand pump for filling the



(*Courtesy of National Supply Co.*)

FIG. 120.—Typical installation of Ideal-Hill weight indicator.

oil system. This device is available in two sizes, designed for maximum hook loads of 200 tons and 300 tons, respectively.

Two other types of weight indicators should be mentioned. The Line Scale Company's indicator is attached to the dead line of the hoisting cable and, by a system

of levers and a spring pressure gauge, indicates the derrick or bit load directly on the gauge dial. The MacClatchie weight indicator utilizes an enclosed diaphragm, actuated by hydraulic pressure created by tension in the hoisting cable. The device is mounted in a metal frame supporting three sheaves over which the fast line of the hoisting cable passes, with slight deflection. The indicating pressure gauge incorporates a quickly adjustable means of compensating for the number of lines supporting the traveling block, so that direct readings in tons can be obtained on a single gauge dial.

Table Torque.—The torque applied to the drill pipe by the rotary table is a convenient measure of the energy expended in drilling and of the twisting effort responsible for the torsional strain developed in the drill column. Knowledge of the torque applied enables the driller to know at all times the amount of power required to rotate the drill column. This is a useful index in interpreting bottomhole conditions. For example, if the bit is dull, balled up with clay or off gauge, or if a formation change occurs or the hole departs from its normal vertical course, there should be some change in table torque if the same rotating speed and bit pressure are maintained.

In a steam-powered rotary rig, a recording pressure gauge on the engine side of the throttle valve provides a convenient torque indicator inasmuch as the torque applied is directly proportional to the manifold steam pressure. A wattmeter recording the power input to the motor may serve the same purpose when the rig is electrically driven. Frictional losses in the power-transmission mechanism are such that the power input on the prime mover is approximately proportional to the twisting effort transmitted to the drill column.

Pump Pressure and Volume of Fluid Circulated.—The efficiency of a rotary drilling operation depends largely upon the capacity of the slush pump or pumps, the pressure that can be maintained on the circulating fluid and the volume of fluid that can be circulated through the well at this pressure. The pumps employed must have adequate capacity; otherwise efficiency will be low. During the last two decades there has been a notable advance in this phase of rotary rig operation, the pump pressures and volumes circulated in modern drilling operations being several times those of twenty years ago.

A variety of factors influence the pressure necessary in the drilling fluid delivered by the pumps. The primary purpose of imposing pump pressure is to cause flow of fluid at the necessary rate through the well to lift drill cuttings most effectively. To do this, certain frictional resistances must be overcome. First, the shear resistance or internal resistance to motion of the fluid itself must be overcome. The drilling fluid may, from some points of view, be regarded as a semiplastic solid that offers flow resistance proportional in some degree to the length and mass of the column of fluid to be set in motion and its viscous and

thixotropic properties. Second, the pump pressure must be sufficient to offset the flow resistance offered by the drill column and surface connections to movement of fluid through them at the desired rate. The pump manifold and standpipe, the rotary hose, swivel, kelly, tool joints, drill collar and apertures through the bit all offer definite flow resistance in addition to the frictional flow resistance offered by the drill pipe. And third, there is the resistance to flow through the annular space between the walls of the well and the drill column. The flow resistance varies not only with the size and length of the flow channel (or depth of the well), but also varies with the viscosity and density of the fluid and with the flow velocity.

Complex empirical formulas are available for computing, approximately, the pressure loss in pumping drilling fluid through a given length and diameter of drill pipe, and through tool joints of different patterns, but they are probably not of general application. Because of variations in diameter of the well and turbulence induced by drill collars, tool joints and protectors, no satisfactory formula for computing pressure loss during flow through the annular space has yet been devised. The problem of computing well friction in circulating drilling fluid through the drill column and annular space is apparently quite complex, and we have as yet no dependable means for computing it on a quantitative basis.

The volume of fluid that may advantageously be circulated in a rotary drilling operation will depend upon the nature of the formation in which the bit is operating, the diameter of the well, the size of the drill pipe, the type of drilling bit used and the physical properties of the fluid. More fluid must be circulated when drilling very permeable formations in order to compensate for fluid draining away from the well into the formation. Heavy clays that tend to ball up on the drilling bit require a greater volume of fluid in circulation than harder granular rocks. The larger the diameter of the well and the more rapid the rate of advance of the drill, the greater will be the volume of fluid required to remove effectively the quantity of drill cuttings formed. Some drilling bits make more rapid progress than others and the volume of fluid circulated must be increased proportionately. In a hole of specified diameter with a given rate of fluid circulation the larger the diameter of the drill column, the smaller will be the cross section of the annular space between the drill pipe and the wall of the well, and the more rapid will be the ascending velocity of the circulating fluid. The most important consideration in determining the volume of fluid to be circulated is that of attaining a suitable ascending velocity in the annular space to lift effectively the coarser drill cuttings. Little is known as yet concerning the ascending velocity that is necessary or that would be most

effective. The denser and more viscous drilling fluids require less ascending velocity in the annular space than the lighter and less viscous fluids.

From one point of view, the circulating fluid is but a means of transmitting energy to the bottom of the well: energy to help excavate material in the path of the bit and lift it to the surface. The energy transmitted is measured both by the volume of fluid circulated per unit of time and by the pressure imposed upon it by the pump. Energy consumed in forcing fluid through the drill column is wasted insofar as any useful purpose is served. Consequently, everything possible should be done to reduce pressure loss in the surface connections and drill column. Energy may be conserved to an important degree by using full-hole types of drill pipe and tool joints, and large passages through the surface connections. Studies have indicated that with $5\frac{9}{16}$-in. drill pipe, equipped with full-hole tool joints, a given rate of flow in a 5,000-ft. well can be maintained with 38 per cent less pressure than with tool joints of regular pattern. Moderate increase in the size of drill pipe—as from $4\frac{1}{2}$ to $5\frac{9}{16}$ in.—results in a considerable increase in the rate of progress of the drill in some types of formation. Less of the energy of the drilling fluid conferred by the pump is consumed in the larger pipe in transmission to the bottom of the hole; more of it is conserved to be utilized in the work of lifting cuttings.

In soft formations, progress of the drill may be aided materially by the jetting action of the drilling fluid as it is discharged from the apertures in the bit against the cutting elements of the bit and the bottom of the hole. This jetting effect may be made more effective either by increasing the volume of fluid circulated per unit of time or by increasing the velocity of fluid as it emerges from the bit. With a given volume-rate of flow, the jet velocity may be increased by reducing the size of the apertures in the bit. In soft formations, the rate of advance of the drill increases directly with the speed of the pump or the volume-rate of fluid flow and there is every advantage in increasing flow velocity to the practical limit. In hard formations, there is apparently an optimum rate of flow above which no material advantage is gained.

The kinetic energy residing in the circulating fluid as it rises from the bottom of the well is very inefficiently applied in lifting drill cuttings to the surface. The foot-pounds of work theoretically accomplished in elevating cuttings represents but a small part of the total energy with which the fluid is endowed. For a given quantity and size of particle to be lifted, there is probably a certain ascending velocity that will be most efficient. The cross section of the annular space, which, for a given volume-rate of circulation, determines the ascending velocity, must be of such size as will provide this most effective velocity. The relative

diameters of the well and the drill column will be important considerations in determining this.

From a practical operating standpoint, duplex steam pumps are operated at about 50 strokes or 165 ft. of plunger travel per minute (for 20-in. stroke). Pump delivery pressures as high as 3,000 lb. per sq. in. are possible by use of small-bore pump liners, high steam pressure and high plunger speed, but seldom will more than 1,200 lb. pressure be required, and usually much less. The pump pressure normally increases with the depth of the well at the rate of about 100 lb. per 1,000 ft. of depth. Ascending velocities in the annular space will vary from 50 to 300 ft. per min., the usual range being from 100 to 200 ft. per min. The volume-rate of flow to achieve such ascending velocities will depend upon the relative diameters of the well and the drill column, but will vary from 100 to 1,000 gal. per min., the usual range being from 300 to 800. Such capacities and delivery pressures are possible with hydraulic cylinders 7 to 8 in. in diameter and 18- to 20-in. piston strokes, operating with duplex steam pumps at 50 r.p.m. and with 300 to 350 lb. steam pressure. A 19- by 9¼- by 22-in. duplex pump operated at a plunger speed of 100 ft. per min. delivers about 700 gal. per min. A triplex pump 18 by 7¼ by 20 in. in size delivers 640 gal. per min. at the same speed. The largest slush pumps in general use today deliver about 900 gal. per min. Such pumps will serve all ordinary requirements if ample steam pressure to permit of moderate speed increase can be furnished when necessary.

Information concerning the output of the pump is readily made available to the driller. The volume of fluid circulated is determined by timing the strokes of the pump. Simple computations based on the diameter of the pump cylinders, length of stroke and pump efficiency give the capacity per stroke; or this information may conveniently be had by reference to pump displacement tables. The fluid delivery pressure may be indicated and continuously recorded with the aid of pressure gauges of special design. These visually indicate and record pressures as high as 5,000 lb. per sq. in. and are equipped with diaphragm protectors, pulsation dampeners and a retarding device that reduces the sensitivity of the instrument to the higher pressures.

Drilling Control Instruments.—In previous sections, mention has been made of devices for indicating and recording the weight on the hoisting cable, the speed of rotation of the rotary table, torque on the drill column and the pump pressure. The indicating and recording gauge for the weight indicator, the torque gauge, the table tachometer and the pump-pressure gauge may all be assembled conveniently in a steel cabinet, mounted on a pedestal near the driller's position on the derrick floor. Flexible connections are made between this cabinet and the working positions of the various instruments. The several indi-

cating dials are thus always visible to the driller and may be indirectly illuminated to facilitate night use. Continuous charts made on the recording instruments are removed each day to the operator's field office where they may be analyzed by the field executives and then filed for future reference.

Several manufacturers feature such assemblies of drilling control instruments and they are widely used in modern rotary rigs. That illustrated in Fig. 119 is a well-known type marketed by the pioneer manufacturer of drilling control instruments. This assemblage of indicating and recording gauges provides separate dials for visual indication and a chart for continuous recording of data concerning several phases of rotary rig operation. On one 12-in. dial is indicated the weight on bottom, the load on the derrick, the slush-pump pressure, the torque on the drill column and the rotary table speed. Simultaneously and continuously these data (except the table speed) are recorded with three separate pens on a single 12-in. chart revolved once in 24 hr. by clockwork.

Rate of Penetration in Rotary Drilling.—Many different factors influence the rate of penetration of the drill. Important among these are the character of the formation, the size and type of bit in use and its rotational speed, the bit pressure, the pressure and rate of circulation of the drilling fluid, and the quality of the equipment and skill of the driller. Less rapid penetration is achieved in the harder rocks. Formations that cave readily, that are steeply inclined, or that show a tendency to "heave" into the well may compel a slower rate of advance than is mechanically possible. Much depends on adoption of a type of bit suitable for the formation to be drilled. Because of the greater amount of material to be pulverized and removed from the well, large-diameter holes are usually drilled less rapidly than smaller diameter holes. High rotational speeds make for more rapid penetration if appropriate bit pressure is used. Increased bit pressure likewise yields more rapid progress. High volume-rates of circulation result in more rapid penetration than lower rates, particularly in soft formations. Large-diameter drill pipe conserves energy and, within limits, results in more rapid penetration than smaller sizes. These factors have all been adequately discussed in the preceding sections. Two factors, however, have not as yet been emphasized adequately; these are the size and quality of the drilling equipment and the skill of the drilling personnel.[26]

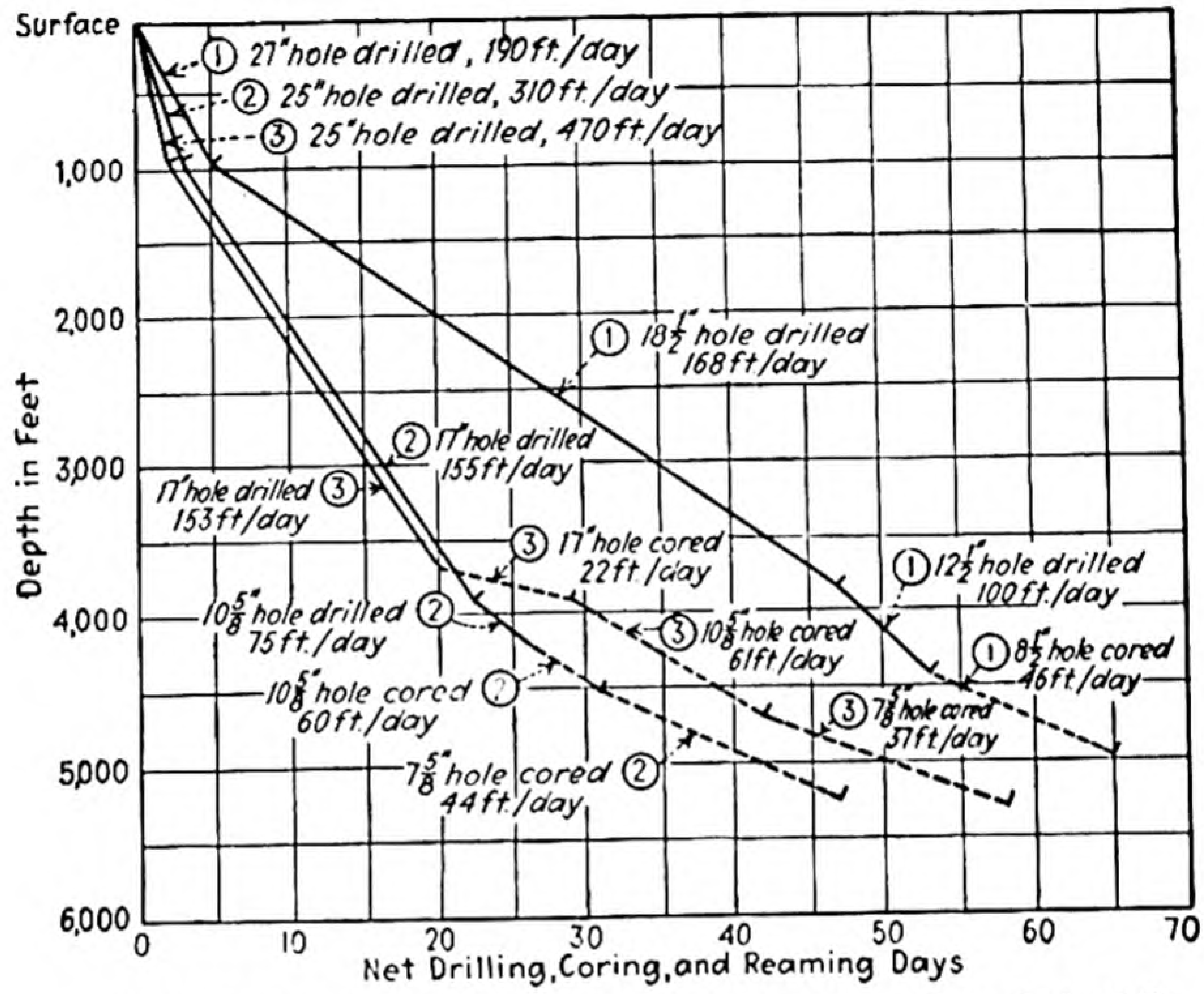
In analysis of the data furnished in response to a questionnaire, in which the results of more than 500 drilling operations in representative American fields were carefully studied by competent authorities, it was concluded that personnel and equipment efficiency were more important than any other factors influencing the rate of penetration in drilling. Rotary drilling technic has progressed far beyond the primitive

methods and practices of earlier days and is now an art in which technical knowledge and skill play a very important role. From the equipment standpoint, great progress has been made in better design and proportioning of equipment and use of better materials and manufacturing workmanship. The drilling records of recent years, representing operations in which wells have been drilled to previously unattainable depths in but a fraction of the time previously necessary in drilling to much shallower depths, are largely a result of superior equipment and knowledge and skill of drilling personnel.[7]

In the Southern San Joaquin Valley of California, where great thicknesses of comparatively soft shales and sands must be penetrated in reaching the oil-bearing formations, a well was drilled to a depth of 11,450 ft. in 36 days 9 hr., including the time spent in "running" and cementing casing. Another well in this same region was drilled to a depth of 12,878 ft. in 51 days. A well in southern Louisiana has been drilled to a depth of 11,934 ft. in 58 days. This included time spent in running and cementing casing, making surveys and electrical logs and taking numerous cores. Drilling conditions at this well were not especially favorable. With modern equipment, it is not unusual to drill comparatively shallow wells to depths of from 1,000 to 5,000 ft. in but a few days. In the first day of surface digging, many hundreds of feet may be drilled. In the shallower fields of the San Joaquin Valley, California, for example, using a portable rotary rig that can be moved from one location and be actively engaged in drilling at another in less than a day, as many as seven wells have been drilled to depths of about 2,000 ft., in a single month, or an average of about four days per well. These are records for their localities and the average rate of penetration is doubtless much less, but they are indicative of what can be done under favorable conditions. One authority, in reporting on time spent in drilling to various depths in the California coastal district, suggests that 2,000-ft. holes should be drilled in 5 days; 4,000-ft. holes in 12 days; 6,000-ft. holes in 22 days; and 9,000-ft. holes in 80 days.

The hourly rate of progress in actual drilling will vary widely, depending upon the conditions enumerated in the foregoing paragraphs. In a hard limestone or a well-cemented sandstone, even with a suitable bit and proper control of operating conditions, the rate of penetration may at times be as little as 1 ft. per hr. Soft, semiconsolidated formations, on the other hand, can often be drilled at rates of 20 ft. per hr.; in some instances, penetrations as great as 80 ft. per hr. have been attained. The rate of penetration is more rapid at shallow depths than at greater depths because of the greater percentage of time spent in changing bits in the deeper drilling and because, in general, the deeper formations are harder and more thoroughly consolidated. It is also

more difficult to control the operation of the equipment as the depth increases, and more time is spent in handling equipment because of the greater loads and hazards presented. Thus, in the drilling-progress chart for well No. 2 in Fig. 121, the average rate of progress in drilling the first 1,000 ft. of hole was 310 ft. per day, while at depths of from 4,000 to 5,500 ft. the rate of progress was only 44 ft. per day.



(*After B. Barkis and R. D. Copley in Am. Petroleum Inst. Bull. 210.*)

FIG. 121.—Drilling-progress charts for typical California oil fields.

In the over-all, elapsed time spent in drilling a well, ordinarily less than half is spent in actual drilling. Many other operations are necessary in the completion of a well, and much time is spent in running casing, in cementing operations and waiting for cement to harden, in coring, in surveying, logging and formation testing, fishing, well-completion operations, etc. The following time-distribution summary indicates the time spent in various phases of the work of drilling a 7,400-ft. well in a California field, using a gas-engine powered rig. It will be noted that of the total of 91 days spent in drilling this well, the drilling bit

Item	Days	Item	Days
Drilling bit on bottom	38.0	Pulling cores	2.7
Running in drill pipe	6.6	Lost time (cementing, etc.)	13.2
Pulling out drill pipe	8.7	Repairs	4.4
Circulating	4.3	Fishing	10.3
Surveying	1.8		
Making connections	0.9	Total time	90.9

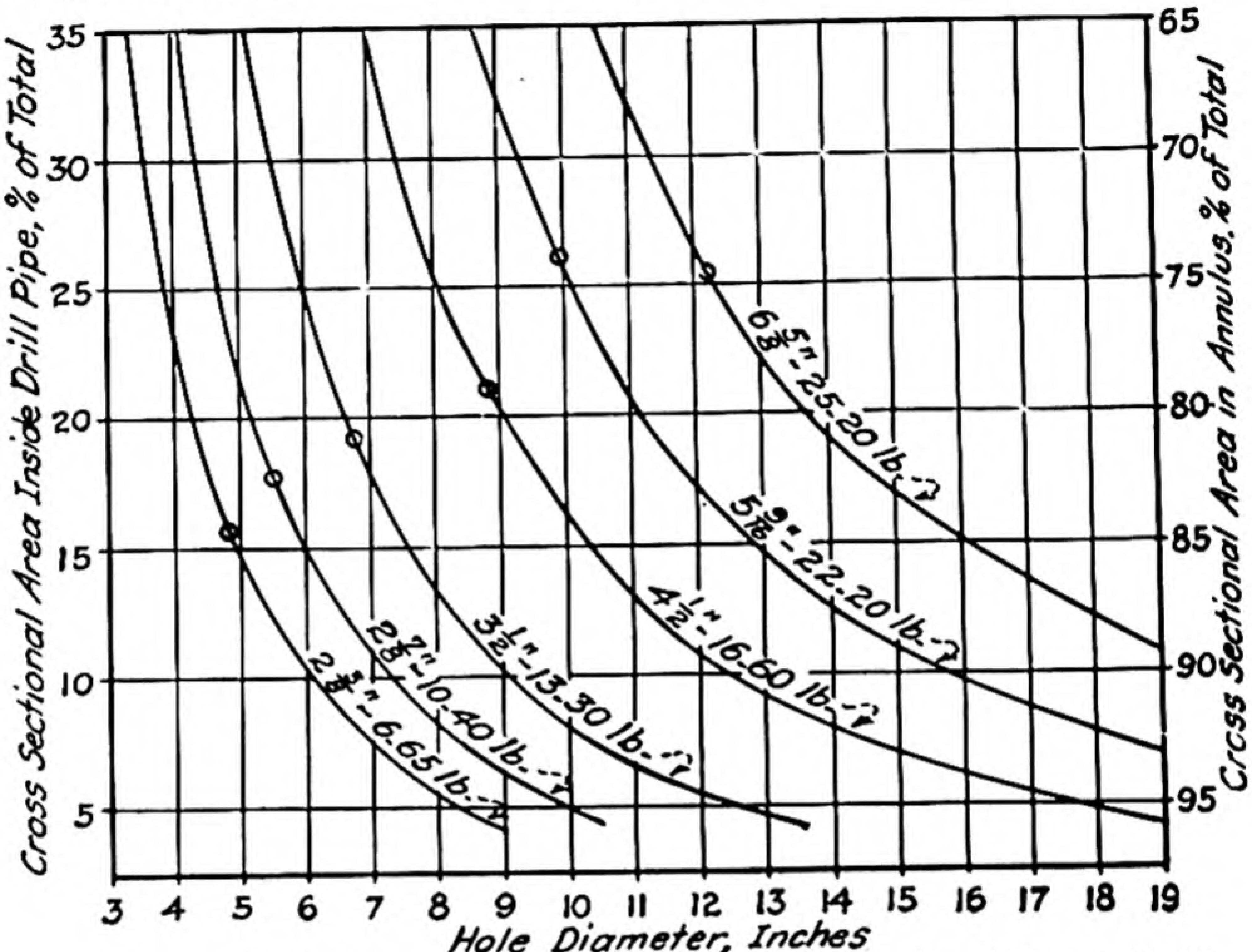
was "on bottom" for a time aggregating only 38 days, or about 42 per cent of the total time.

Well Diameters.—The size of hole that should be drilled will depend upon the purpose for which it is to be drilled, the depth to be attained, the character of formations that must be penetrated and the casing program to be used. An exploratory well drilled primarily for stratigraphic information may be but a few inches in diameter. On the other hand, a well drilled for the purpose of securing detailed subsurface information in an area where little or nothing is known of the stratigraphy, and where the depth to be attained cannot be estimated with certainty in advance, may have a large starting diameter in order to permit of making several reductions in casing size and contending with any mechanical difficulties that may be experienced. A well drilled for production purposes must have a sufficiently large finishing diameter to accommodate a liner that will receive a pump of suitable size to afford the rate of production desired, and allow reasonable space for oil accumulation and gas segregation. In multizone situations, a well is often completed with a diameter greater than otherwise would be necessary, in order that it may, at some future time, be deepened and a smaller size of liner set for production from a lower zone.

Where great depths are to be attained in areas that require several successive reductions in casing diameter, starting sizes may be as large as 24 in. In this, an 18⅝-in. surface casing may be cemented. Through this, a hole 16 in. in diameter may be drilled to receive 11¾-in. casing; and through this, a 10-in. hole for 8⅝-in. casing. And finally, a hole 7 in. in diameter may be drilled through the oil-producing horizon to receive a 5¾-in. liner. In the section dealing with casing design and installation, other appropriate casing programs are suggested (see pages 411 to 436). In general, the size of hole drilled should be at least 1½ in. larger in diameter than the outside diameter of the casing that it is proposed to set in it; for larger sizes of casing the difference between the hole and the casing diameters may be as much as 5 or 6 in. This differential should be somewhat greater in soft formations that display caving tendencies and in very permeable formations that are likely to accumulate thick mud cakes on the walls, than in harder and less permeable formations.

The question of the size of hole to be drilled is determined largely by economic considerations. Large-diameter casings are costly and usually it is more expensive to drill the larger diameter holes. The advantages of the large-diameter wells from a production standpoint must be balanced against their greater cost. There is necessarily a limit of size below which the well no longer efficiently serves its intended purpose, and it is false economy to reduce casing and pump

clearances to the point where there is hazard of mechanical difficulties developing in the conduct of cementing operations and installation of well equipment. The lower drainage efficiency of the smaller diameter well must also be kept in mind. The economic aspects of the problem of well diameter have previously been discussed in the chapter dealing with the principles of oil-field development.[2]



(*After W. W. Moore in Production Bull. 226, Am. Petroleum Inst.*)

FIG. 122.—Graphs showing relative cross-sectional areas inside and outside of drill pipe of different sizes in holes of different diameters.

Within recent years, there has been a notable trend toward the use of smaller diameter wells in oil-field development. Proration restrictions and economy in casing expense have made this practice financially attractive. In these "slim-hole" programs, the most common sizes of casing placed through the oil-producing horizon are 7 and 5½ in. For these sizes of casing, holes about 9 and 7 in. in diameter, respectively, should be drilled. Oil strings as small as 4½ in. are used in some fields. For this, a 6½-in. hole is sufficiently large. Surface strings need seldom be more than 11 in. in diameter, for which a 12½-in. hole will provide sufficient clearance.

Drill-pipe Diameters.—The size of drill pipe that should be used in drilling holes of different diameter is another question that should receive careful consideration. As explained in a previous section, a proper balance must be sought between the cross section of the interior channel of circulation through the drill column and that of the annular space outside of the drill column. The inside channel should be as large as possible in order to reduce flow resistance to a minimum, and

the outside channel must be small enough to provide proper ascending velocity for the circulating fluid. This implies a large-diameter drill pipe, usually only slightly less than half the diameter of the hole for the range of hole diameters normally used in rotary drilling. Large-diameter drill pipe is also advantageous in that it is more secure against failure resulting from excessive stresses in drilling. However, large-diameter drill pipe is more costly than smaller pipe and more power and heavier surface equipment are necessary in handling it. Sufficient space must be left about the drill column to permit of safe operation of overshots and other devices sometimes necessary in the conduct of fishing operations.

Figure 122 presents a series of graphs illustrating the normal range of application of drill pipe of different standard sizes, and the corresponding sizes of cross-sectional areas of the interior and exterior flow channels. Appropriate flow velocities are provided, as indicated by the circled points on these graphs, by using 6⅝-in. drill pipe in drilling a 12¼-in. hole; 5$\frac{9}{16}$-in. drill pipe in a 9⅞-in. hole; 4½-in. drill pipe in an 8¾-in. hole; 3½-in. drill pipe in a 6¾-in. hole; and 2⅞-in. drill pipe in a 5-⅝in. hole.

Power Consumption in Rotary Drilling.—As explained in a previous chapter, power consumed in rotary drilling is utilized principally in (1) operation of the circulating pumps, (2) hoisting operations and (3) rotating the drill column.

In operation of the slush pumps, there is naturally a considerable variation in power consumption. Changes in depth and variation in clearance between the drill pipe and the wall of the well, in the size of drill pipe used, in the drilling-fluid viscosity, in the volume of fluid circulated and pressure conditions maintained combine to produce an extremely variable power demand. The necessary pressure and power increase rapidly with depth, though the volume of fluid circulated diminishes with depth owing to progressive reduction in the diameter of the well. Studies made in the drilling of several wells in the Ventura field of California indicated that the necessary pump pressure gradually increased with depth to a maximum of 700 lb. sq. in. at about 7,000 ft., while the volume of fluid circulated diminished from 50 to 25 cu. ft. per min. Under the conditions here presented, about 90 hp. was required to operate the pumps at a depth of 5,000 ft., and 130 hp. at 6,000 ft. where the maximum power demand was reached. Because of reduction in well diameter, power consumption at depths in excess of 6,000 ft. was less than at shallower depths. Necessary pump pressures increased uniformly at a rate of about 100 lb. per 1,000 ft. of depth. As explained in a previous section, the pump pressure and volume rate of fluid circulation will vary with the rate of progress of the drill. Recent advances

in drilling technic, resulting in more rapid rates of penetration, have necessitated greater pump capacities and pressures.

A modern heavy-duty slush pump, designed for drilling to depths of from 10,000 to 15,000 ft. and delivering fluid at working pressures as high as 1,000 lb. per sq. in., may require an expenditure of as much as 674 hp. In the largest sizes of pumps, capacities are sometimes as great as 1,450 gal. per min.; with small liners in the water ends, delivery pressures may be increased to as much as 3,000 lb. per sq. in. A 15½- by 8½- by 20-in. duplex steam-driven slush pump, operating on 300 lb. steam pressure and delivering fluid at 900 lb. pressure, will develop about 500 hydraulic hp. at 50 strokes per minute.

The power consumed in hoisting operations increases with the weight of the drill column and with the speed of hoisting. This weight, of course, increases with the depth of the well and with the size of drill pipe employed. Weights of drill columns used in drilling the deeper wells (up to 15,000 ft.) have reached as much as 250,000 lb. The heavier loads are necessarily hoisted at slower speed. More lines are strung on the hoisting block to increase the mechanical advantage of the hoisting equipment, and this reduces the speed of hoisting. The driller also utilizes the several gear ratios afforded by the draw-works and power-transmission mechanism in adapting the available power to the loads imposed. The actual speed at which the drill pipe is lifted in hoisting operations therefore varies greatly. With a long, heavy drill column in the well, the hoisting speed may be only a small fraction of that with which the last few stands of drill pipe are handled, when the bit is nearing the surface. A maximum power consumption at the rate of 245 hp. was noted in one instance where 4,000 ft. of 6⅝-in. drill pipe was being lifted with eight lines on the hoisting block, a three-speed draw works and a 12- by 12-in. twin steam engine. It is apparent that hoisting operations, though occupying only perhaps 10 per cent of the total time in rotary rig operation, occasion a considerable expenditure of energy during this period. Indeed, operation of the draw works in drawing out drill pipe often requires the maximum expenditure of power that the power plant is called upon to furnish, and may determine, more than anything else, the power-plant capacity that must be provided. A desire to hasten the process of hoisting drill pipe, and thus reduce the round-trip time necessary to change bits, has often been responsible for provision of a surplus of power in excess of normal operating requirements. Thus, heavy-duty draw works are often equipped with a 14- by 14-in. twin-cylinder steam engine capable of delivering 1,500 hp. at 400 r.p.m. when operated on 300 lb. steam. Yet, a power plant developing only two-thirds of this power may be sufficiently powerful and certainly more economical, though perhaps a little slower

in lifting the drill column during the 10 per cent or less of the time spent in this operation.

The size of engine necessary in deep-drilling operations will depend largely upon the steam pressure available. A twin-cylinder 12- by 12-in. engine will be adequate to meet all reasonable hoisting requirements with 300 to 350 lb. steam pressure; for pressures less than this, a larger engine will give better performance. For wells of moderate depth, a 12- by 12-in. engine will be adequate even though the steam pressure is as low as 250 lb.

The power consumed in rotating the drill column while drilling is in progress represents but a small part of the total power expended in a normal rotary drilling operation. In shallow drilling, this may be as low as 20 hp. and even in deep drilling, it will seldom exceed 50 hp. At a given rate of rotation, power consumed in this phase of the work is almost constant while drilling is in progress and does not vary greatly with depth or with the size of the drill pipe and bit. However, the recent trend toward more rapid rotation rates has resulted in an increasing power demand. In one instance, for rotation at 380 r.p.m., 18,000 lb. of 300 lb. steam was required per hour, while at 130 r.p.m., the steam consumption was only 3,600 lb. per hr.

Power Correlation of Rotary Drilling Equipment.—For smooth functioning of the rotary equipment, it is important that the size, capacity and power consumption of the several parts of the rig be properly proportioned. Circulating pumps too small in capacity, or incapable of delivering fluid to the well at sufficient pressure, will reduce the rate of progress that an otherwise well-equipped rig would be able to attain. Insufficient flexibility in speed and mechanical advantage afforded by the draw works and hoisting gear will retard the speed of handling drill pipe and casing. A flexible and powerful draw works and heavy-duty pumps will not attain their highest efficiency if handicapped by an inadequate power plant. The size and weight of the derrick, rotary crown blocks, hoisting blocks, hoisting cable, swivel, drill column and minor parts of the rig must be proportioned to the loads imposed and the power to be transmitted. The depth to be attained in drilling will be a controlling factor in determining the weight and power requirements of various parts of the rig. In heavy-duty rigs now available on the market, every part is designed for efficient functioning and proper correlation with other parts to depths as great as 15,000 ft.

DIFFICULTIES ENCOUNTERED IN ROTARY DRILLING

Difficulties of many kinds are experienced in the conduct of rotary drilling operations. Their causes, methods of avoiding them and

remedial measures that may be taken after they occur are important aspects of the driller's art. Holes may depart from the vertical and require straightening. The drill column may fail while in service, necessitating a fishing operation to retrieve the detached lower end of the column. A "washout" may occur at a tool joint or collar, endangering the security of the drill column and partial loss of circulation. The drill column may become frozen or held fast in the well by accumulated mud and drill cuttings or caving of the walls. The well may become oversize by erosional effect of the circulating fluid in soft formations; or undersize by loss of gauge of the drilling bit. The drill pipe may become "keyseated" in the wall at one side of the well. The hole may "bridge" by caving of the walls or by influx of heaving shale. A blowout or violent and destructive expulsion of drilling fluid from the well may occur. These and other accidents and difficulties encountered in the routine of drilling may occasion serious delays or, in some instances, even abandonment of the well.

Crooked Holes.—It is important that wells be drilled vertically and straight for a variety of reasons. Principles of property ownership require that line wells do not illegally encroach on neighboring properties. The practice of spacing wells apart at equal distances to secure uniform drainage loses its significance if the wells are crooked. The wells develop interference, and a lower over-all percentage extraction of the available oil is secured than if the wells penetrate the producing horizon at uniformly spaced points. If the record of thickness of formations penetrated is of importance in geologic correlation studies, departure of a well from the vertical will be productive of very misleading information. Some confusing situations have been presented where wells only a few hundred feet apart at the surface have shown great differences in depth and thickness of "marker" horizons and remarkable differences in productivity on completion. Edge wells may be deflected and entirely miss the productive sands. A well on good acreage may drift into poor neighboring acreage and vice versa. Proper correlation is important in determining points at which casing strings are to be set and cemented and in estimating depth to production.

In drilling and casing wells, a crooked hole introduces mechanical difficulties, at times requiring abandonment of the well. Twistoffs of the drill column are more common, and the resulting fishing jobs are more difficult and costly. More sidetracking jobs are necessary. There is great power consumption in rotating drill pipe in a crooked hole, owing to excessive friction. It is difficult to insert casing and the casing may be damaged in adapting itself to abrupt changes in direction. It is often difficult to operate cable tools in a crooked hole: the casing may become "line cut" and collapse, because the drilling cable and sand line

always scrape on one side. Crooked holes on adjoining locations sometimes come too near each other at depth, and one loses circulation to the other, perhaps causing mudding of the producing sands about both wells. In some instances, wells have actually intersected at depth. A crooked hole requires the drilling of greater footage to reach a given depth than would be necessary in a straight hole, and the cost of drilling this additional footage and time lost are important considerations.

A crooked well is also productive of difficulties during the operating stage, particularly if it is to be pumped. The column of sucker rods rests against the tubing—always against one side in a crooked hole—and its oscillating movement wears holes in the tubing and wears away the metal about the screw joints by which the rods are held together. There are undue wear on the pump plunger and excessive power consumption due to frictional losses. Fishing troubles in retrieving parted rods are accentuated. In pumping, there is a considerable elastic movement of the tubing, with resulting wear of the tubing collars and casing—all on one side if the hole is crooked.

Some almost unbelievable deflections of rotary-drilled wells have been reported as a result of carefully made surveys with dependable instruments. Inclinations from the vertical as great as 70 deg. have been noted in some instances. The deflection does not always continue in the same direction; perhaps the hole may drift in one direction for a time, then turn in some other direction. It seems difficult to conceive of the heavy drill pipe operating successfully in wells having such deflections, but when it is considered that the length of the drill column may be many thousands of times its diameter, it is realized that, as a whole, it may be quite a flexible unit.

A survey of a 5,100-ft. well drilled by the rotary method in the Seminole District in Oklahoma indicated that it had drifted horizontally 2,470 ft. from the starting point and that some 800 ft. of excess hole had been drilled beyond what would have been necessary to reach a comparable depth in a vertical well. One well drilled in a California field was found to have an inclination of 56 deg. from the vertical at a measured depth of 5,683 ft. The vertical depth to this point was only 4,893 ft., which is 790 ft. less than the measured depth, and the horizontal displacement was 2,252 ft. Though drilling was continued to a depth of 6,410 ft., no unusual mechanical difficulties were experienced. These, no doubt, are extreme cases, but the results of 38 surveys of rotary-drilled wells in the California fields, drilled to depths in excess of 6,000 ft., show an average drift from the vertical of 132 ft. per 1,000 ft. of depth, and an average inclination from the vertical of 22 deg. The magnitude of the deflection often increases with depth. It is believed that improved methods of drilling during recent years have been pro-

ductive of much straighter holes than these earlier records would indicate to be customary.[18]

Realizing the importance of avoiding extreme deflections, some operators survey their wells at intervals during the period of drilling and, whenever the deflection exceeds a small amount, say, 5 deg., require that appropriate measures be taken to straighten the hole. This practice is prescribed by the Railroad Commission of Texas in its regulations governing administration of the state's oil-conservation laws. The operator is in most cases not greatly concerned over the direction of the deflection if the amount of the deviation does not exceed 5 deg. and, for such surveys, simple types of clinographs will be found sufficiently accurate (see page 706).

The causes of crooked holes in rotary drilling have been the subject of much discussion among engineers, and careful studies have been made to determine the reasons for wells departing from the vertical and to prescribe appropriate remedies. Development of dependable well-surveying instruments has made it possible to determine the points at which deflections occur and correlate such information with the drilling records. Many authorities agree that excessive bit pressure is probably most frequently the cause of crooked holes. It seems probable, also, that holes are sometimes caused to deviate from the vertical by use of excessive pressure on the circulating fluid. Rapid circulation causes fluid to be jetted through the holes in the bit with a force which is probably sufficient to erode away the walls of the well, possibly forming cavities in soft material, which may cause the drill column to bend and the bit to change its course.[15]

To avoid deflection of wells in rotary drilling, the hole must be started vertically; improper alignment of the drill column during the spudding process may permit the bit to work off at an angle from the vertical at the start of operations. The design of the bit is also an important consideration in avoiding crooked holes. It should be of a form and size that will prevent undue eccentricity during rotation. It should be sharp and dressed to proper gauge. The drill collar, by which the bit is attached to the lower end of the column of drill pipe, should be large enough in diameter and of sufficient length to hold the pipe centrally in the hole and prevent buckling which, under excessive bit pressure, might cause the bit to deviate from its course. Some operators use a few joints of oversize drill pipe just above the drill collar better to resist the bending stresses that result when excessive bit pressure is applied. "Rat holing," or drilling ahead with a small bit and then reaming out to full size—sometimes practiced in core drilling—is considered to be a likely cause of crooked holes, inasmuch as the small drill may start off center. This difficulty may be overcome

by use of guides or pilot bits on the drill column, or by centering the small drill in the well by rotating a diamond-pointed bit on bottom before inserting the smaller tools.

Many drillers believe that hard, steeply inclined strata encountered in drilling tend to deflect the bit so that the axis of the well becomes inclined in the direction of the dip of the formation. Well surveys have shown this to be true in the case of wells drilled with cable tools, but curiously, with rotary tools, the reverse is often true, especially when the formations are not too steeply inclined. Instead of drifting down the dip of a hard stratum, a rotary-drilled hole in many cases turns the other way and tends to assume a course at right angles to the dip of the formation. In very steeply inclined formations, on the other hand, surveys have shown that rotary-drilled wells, like cable-drilled wells, tend to drift down the dip. The tendency of some rotary-drilled wells to deflect into the hard inclined stratum is plausibly explained on the theory that encountering hard formation in the bottom on one side of the hole causes deflection of the drill column or drill collar immediately above the bit toward the opposite side.

Generally speaking, straight holes can be achieved at the expense of slower drilling progress. Many operators find it worth while to use light bit pressures and low circulating pressures and to take all possible precautions to keep the well vertical and straight, even though it means slower drilling progress. The practice of using a heavy drill collar capable of supplying all of the bit pressure needed has done much to solve the problem of crooked holes. In this practice, only the drill collar is subjected to compressive stress and this is made large and heavy enough to carry it without excessive deflection. Frequent use, during the progress of drilling, of surveying instruments to indicate when wells begin to depart from the vertical, makes it possible for the operator to remedy the difficulty before the deflection has become excessive. Plugging back and redrilling under moderate pressure will often straighten the hole. Or a whipstock may be set in the well to deflect it back into its former course (see page 371).

Drill-column Failures.—The possibility of failure of the drill column is an ever-present hazard. Weakened by cumulative wear and fatigued by severe and repeated stress, a twistoff may occur when excessive bit pressure is inadvertently applied. Screw joints may become loosened by vibration; or, as a result of improper assembly, washouts and fractures at the base of the threads may result. Not many years ago, such difficulties were common and were regarded as inevitable. Much time was spent in expensive fishing operations to retrieve parted drill pipe. During more recent years, because of improved design and materials and better control of bit pressure, drill-column failures have been much

less frequent. However, the nature of the service is such that we can never expect entirely to avoid such difficulties, and the driller must be ever on guard to prevent them and, when they occur, to take the necessary remedial measures as promptly as possible.

As explained in an earlier section, when in use, the drill column is subjected to a combination of stresses involving tension, compression, torsion and flexure, with harmonic vibration and shock loads that are exceedingly destructive. Flexure may be severe under compressive stress where the drill column does not receive adequate wall support in oversize holes, or where cavities are washed out of the wall of the well in soft formations, by the drilling fluid. A crooked "kelly" or bent section of drill pipe may also create severe fatigue stress. The most common type of failure is fatigue failure, especially when accelerated by corrosion, resulting in progressive fracture along the planes formed by the crystalline structure of the metal. Such fractures often occur at the root of the last-engaged thread in joints between drill pipe and collars and tool joints. Corrosion greatly reduces the resistance of steel to fatigue stress, and it has been suggested that the corrosive tendencies of some drilling fluids, resulting from presence of free oxygen, may be reduced by addition of 100 to 200 parts per million of sodium sulphite.

Though threads are cut on upset ends of the drill pipe and the metal is no thinner here than elsewhere, the last-engaged thread in a threaded joint is a point of highly localized stress induced by "wobble" or flexure with slight motion of one part of the joint on another. In some cases, the initial fracture may be induced in the process of cutting threads. Any weakening of the surface fibers of the metal, as in cutting the V notch of the thread—even a transverse scratch on the surface—may create an incipient fracture which is gradually enlarged and extended until the metal fails under stress. Some failures are traceable to split pipe or collars, resulting from defective material.

It is believed that torsional stress alone is seldom the cause of failure, though shock loads resulting when the rapidly rotating bit suddenly stalls as a result of excessive penetration are undoubtedly severe. The column may acquire many degrees of torsional twist at such a time, and the sudden release and reversal of this stress when the bit finally breaks free are also destructive. Large tangential forces are imposed on the threaded sections in making up screw joints between component members of the drill column. These are relieved somewhat by the lubricant used, but "galling" of threads as a result of excessive stress may be a cause of joint failure. "Jumped" pin failures, or cross fracture at the base of the pin in the tool joint, are traceable to this force, perhaps assisted by the tendency of the joints to "make up" under com-

pression in the well. Security of the tool joints under stress depends upon the frictional hold of the joint shoulders. If these shoulders become damaged by impact in "stabbing" joints in making up the drill column, they may not seat properly and the resulting "wobble" or universal-joint action of the loose parts may cause rapid wear and ultimate failure. Extreme tension under the influence of heavy loads may stretch drill-column tool joints so that they do not seat properly.

The tool joints and collars of the drill column may be well designed and proportioned to absorb the stresses imposed when new but, after a period of use, abrasion and wear against the wall of the well and the scouring effect of gritty fluid, both inside the drill column and out, will result in reduction of wall thickness to the point where the metal is no longer able to resist the stresses imposed. Abrasive wear and loss of metal by the scouring action of sand-laden drilling fluid are minimized by streamlining the tool joints, and may be offset by building up the worn edges and surfaces with hardfacing metal fused on with the oxyacetylene torch. If a threaded joint leaks slightly, or because of wobble mud finds its way between the threads, continued flow of drilling fluid through it will gradually enlarge the opening until a washout occurs. Unless noticed in time, this will eventually so weaken the joint that failure occurs.

To avoid galling of threads in making up drill pipe and tool joints, a suitable lubricant is liberally applied to the threads before the joints are "stabbed." A satisfactory lubricant for this purpose is a mixture of red lead and cylinder oil. Another preferred by many is a suspension of finely ground zinc dust in a medium-heavy grease. Owing to frictional heat in making up joints, the viscosity of the lubricant is greatly reduced and is, for the most part, squeezed out, leaving a thin shell of lead oxide or zinc between the threads, providing a high coefficient of friction that promotes security of the joint. More uniform results are secured by attaching tool joints to drill pipe in a properly equipped shop than in the derrick. Wobble and washouts and last-thread failures may largely be avoided by welding the shoulder between the drill pipe and the tool joints after they are screwed together.

Drilling Difficulties Due to Character of the Formation.—Some of the common difficulties experienced in rotary drilling result from peculiar characteristics of the formation traversed by the well rather than from mechanical control of the equipment. "Bridging" of the hole as a result of caving of the walls, the "heaving-shale" problem, stuck drill pipe, "keyseating" of drill pipe in the wall of the well in a crooked hole in soft formations, oversize and undersize holes and blowouts of the drilling fluid are among the natural hazards that may require special precautionary or remedial measures.

Bridging of the hole is a result of caving of the walls and accumulation of material in some interval that prevents access to the bottom of the well. Usually, the bridge occurs in the upper part of the hole, the relatively unconsolidated formations near the surface displaying greater caving tendencies than those encountered at greater depth. A cave may result from inadequate mudding of walls, from erosional effects of the drilling fluid on the wall sheath owing to excessive rates of circulation, or from allowing the fluid level to subside in the well when withdrawing the drill column. The bridge may not be discovered until the drill column is again lowered into the well. The usual remedy is to lower the drill column until the drilling bit encounters the obstruction, then wash with drilling fluid at maximum pump pressure and volume, but with no more rotation of the drill column than necessary. The drilling bit should, as far as possible, be kept on top of the obstruction, avoiding corkscrewing of the bit downward into the caved material. At such times there is danger of sidetracking the lower part of the hole.

Caving of the walls with the drill pipe on bottom will present a more serious problem. In this case, the drill column may be so thoroughly buried that it cannot be manipulated freely and is apt to become permanently frozen in the hole. This results usually from improper mudding of the walls or the swabbing effect of the drill column in a tight hole. An effort should first be made to break circulation through the caved material, and if this can be achieved, it may gradually be removed by continued high-pressure circulation. The drill column may then be raised cautiously with slow rotation until the bit is above the caved interval. Appropriate measures may then be taken to avoid a recurrence of the difficulty. This may involve special mud treatment, or even use of cement or hydraulic lime to give strength to the wall sheath. If the caved interval is of considerable thickness, it may be impossible to free the drill column and it must then be parted above the caved interval and the lower part sidetracked in subsequent redrilling.

Freezing of the drill column in the well may occasion serious difficulties and should be avoided by all possible means. When formations containing considerable heavy clay or "gumbo" are being drilled, they may be penetrated more rapidly than the material can be hydrated or suspended in the drilling fluid and a mass of clay will accumulate on the drilling bit and about the drill collar. The drill column becomes "logy" and is difficult to manipulate in the well. In trying to lift it, the clay is perhaps further compacted and compressed until it becomes fast in the hole. The remedy for this condition is obviously a slower rate of penetration or greater volume-rate of circulation of drilling fluid. In other cases, owing to use of a poor quality of drilling fluid in a very permeable, low-pressure formation, a thick clay cake may form on

the walls of the well, restricting the annular space between the wall of the hole and the drill column. In drawing out drill pipe from the well, the large-diameter drill collar and bit may scrape off some of this material so that it accumulates above the drill collar and freezes the column in the hole. To avoid this condition, a drilling fluid of better colloidal value should be used, forming a thinner wall sheath.[31]

It is believed that the most common cause of frozen drill pipe is drawing the drill collar up into a "keyseated" portion of the hole. Keyseating may result in a soft formation where drill pipe under tension is operated in a crooked hole. Aided by the cutting edges of the tool joints, the column drills a recess for itself in the wall of the hole. To avoid this, the keyseated intervals should be reamed. Still another cause of frozen drill pipe is found in the settling of drill cuttings and heavy minerals suspended in drilling fluid when circulation is interrupted. Accumulating about the drill collar and bit, they may effectively freeze the column in the hole. Accumulation of drill cuttings is especially likely in intervals where the hole is oversize or where cavities have been washed out of the wall of the well by the jetting action of the circulating fluid. Because of reduced ascending velocity of the drilling fluid in such intervals drill cuttings are apt to accumulate, floating about the periphery of the cavity, but ready to "bridge" the hole around the drill column or settle on the drill collar and bit when circulation is stopped. To avoid this difficulty, a drilling fluid of proper thixotropic properties should be used that will gel and suspend the drill cuttings when circulation fails.[16]

Remedial measures to be taken when the drill column becomes frozen in the well will depend upon circumstances. An effort should first be made to retrieve the column intact. This may sometimes be done by circulating oil or water or alternating "slugs" of gas and water; or the column may be worked alternately up and down, or driven upward with drive clamps on the drill column in the derrick. If the column cannot be freed by such methods, resort must be had to fishing procedures discussed in Chap. XIII, involving backing off in sections, cutting, shooting and "washing over." In anticipation of such difficulty, it is considered good insurance to couple a safety joint in the drill column above the drill collar. This is equipped with a threaded connection that is unscrewed by turning the drill column to the left, but with much less torque than is necessary to break out other joints in the column. This assures that, when the column is backed off the drill collar and bit, the break will occur at the safety joint. The drill collar and bit may then be retrieved by washing over with an "overshot" or casing bowl (see page 555).

Certain types of shales, called "heaving," "caving," "swelling" or

"sloughing" shales, present drilling hazards in certain regions, particularly in the Gulf Coast fields of the United States. These shales, as the names suggest, are unstable under the conditions to which they are subjected in the well and give trouble in drilling through them. It is believed that in some cases instability of these formations results from the steep dip of the beds and their tendency to slide and slip on each other. Often they contain bentonitic clays that absorb water from the drilling fluid and, on hydration, expand into the well. Plastic flow of hydrated clay will explain many of the peculiarities of these occurrences. Some shales contain gas under high pressure, which causes caving of the walls of the well in its effort to expand. In drilling through formations of this kind, an effort is made to maintain high-pressure conditions in the well, and to avoid operations that create high differential pressure between the formation and the well. For example, one might use collapsible, wire-line bits and thus avoid the swabbing action developed by withdrawing drill pipe from a tight hole. The wall of the well might be given a quick wash with hydraulic lime placed in the drilling fluid, before attempting to withdraw the drill column. It is believed that progress can be made by conditioning the drilling fluid to minimize the colloidal tendencies of the clay. Perhaps an oil-base drilling fluid would be helpful.[29]

Oversize and Undersize Holes.—Reduction in the diameter of the bore of a well, resulting from loss of gauge or breakage of the cutting elements of the bit, is a common difficulty, particularly in hard formations. Bits should be replaced before they reach this condition. Undersize holes may also result from formation of unduly thick filter cakes on the walls of the well. Proper conditioning of the drilling fluid to increase its colloidal properties will alleviate this difficulty. The remedy for an undersize hole is to ream the reduced-size interval thoroughly. This should always be done before attempting to run casing through it.

Oversize holes are usually formed in soft formations by the hydraulicking effect of drilling fluid jetted from the bit and by the erosional effect of rapidly ascending fluid through the annular space about the drill column. Caving of the walls may also form extensive cavities. Caliper logs of wells often disclose marked variations in the diameter of wells in different formations. Holes through the softer formations drilled with a 10-in. bit may be 16 in. or more in diameter. This has an adverse influence in reducing the ability of the drilling fluid to lift drill cuttings through the annular space and creates a tendency for the coarser cuttings to float about the perimeter of the flow channel and perhaps freeze the drill column at a critical time when circulation is interrupted. An oversize hole also occasions uncertainty when it becomes necessary to estimate the volume of cement to fill the annular

space between the wall of the well and a column of casing through a given interval. To avoid oversize holes, the pressure of the drilling fluid should be reduced when drilling through soft formations, and every precaution should be taken to minimize caving of the walls.

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CHAPTER X

ROTARY DRILLING: SPECIAL METHODS AND EQUIPMENT

Earlier chapters have been concerned with the conventional methods and equipment used in rotary drilling. In addition, there are a variety of special methods and devices which find only occasional use and which can best be discussed separately. In the present chapter, some of the more important of these, used for special purposes or as a substitute for the methods and equipment ordinarily employed, will be described.

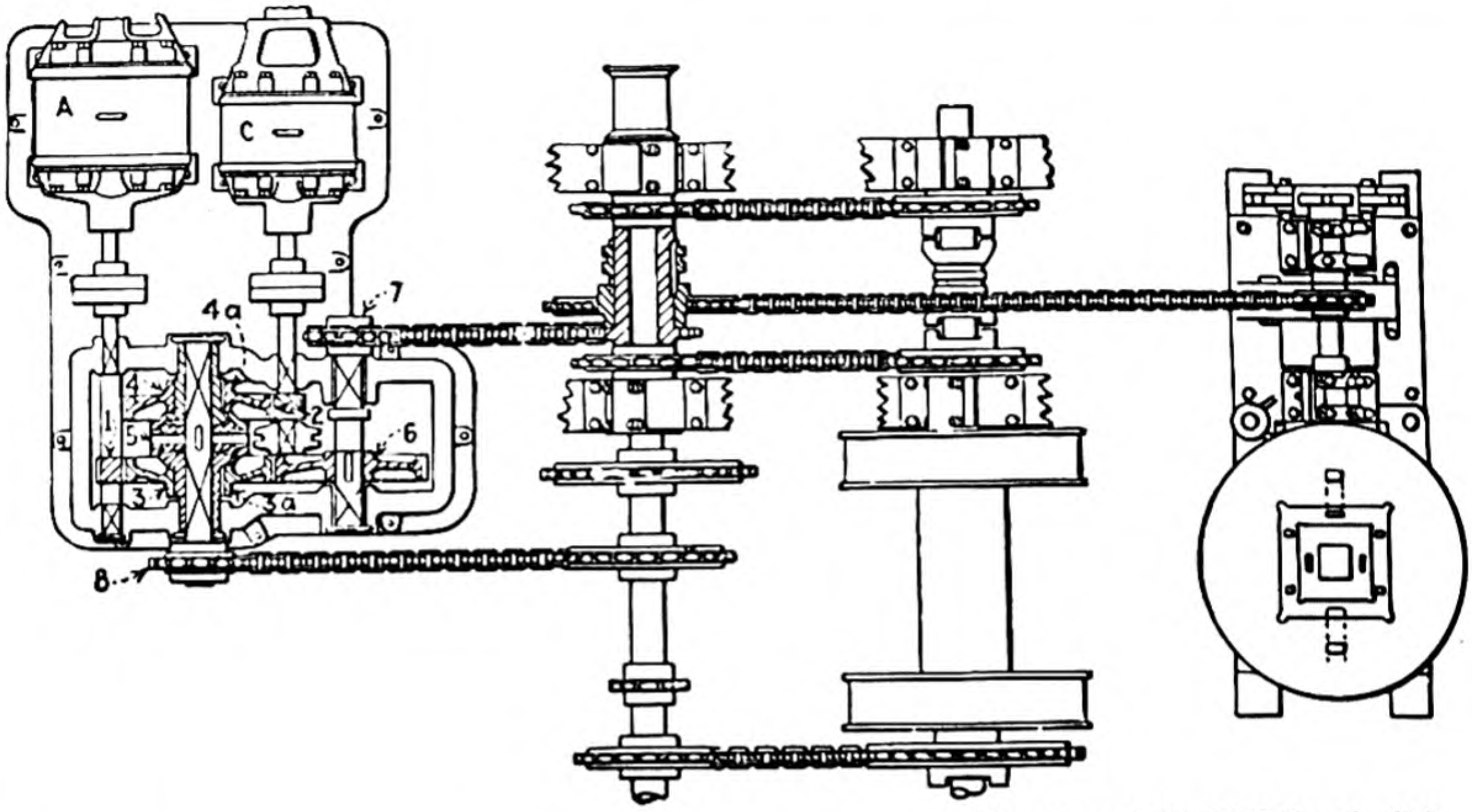
AUTOMATIC FEED AND CONTROL DEVICES DESIGNED FOR USE WITH MECHANICALLY REGULATED ROTARY DRILLING EQUIPMENT

In discussing the mechanics of rotary drilling in Chap. IX, the importance of avoiding excessive bit pressure and drill-pipe torque was suggested. Maintenance of proper mechanical conditions is largely a matter of skillful feeding, or control of the rate at which the hoisting cable is released from the draw-works hoisting drum. Weight indicators, described in an earlier section, assist the driller in maintaining proper operating adjustments, but even with a weight indicator in use we are still dependent upon the faithful and skillful performance of his duties by the driller. The driller is not an automaton. During the long weary hours in his position at the control post at the side of the draw works, his attention wavers occasionally or he is engaged in conversation by one or another of his helpers. Now and then he releases the control brake a little, and when the bit pressure works off somewhat he releases it again. The result is that if we set for him a certain maximum bit pressure, the average pressure applied is apt to be considerably less, and his tendency is to exceed momentarily the maximum in order to make faster progress. In other words, hand feeding is generally conducive to fluctuating bit pressures and results in erratic operating conditions.

As a means of overcoming the difficulties inherent in the manually controlled equipment, efforts have been successfully directed toward the development of devices for automatically controlling bit pressure and drill-pipe torque. Such devices, by maintaining a constant pressure on the bit, drill straighter holes and make more rapid progress and cause fewer twistoffs of the drill column or other breakages of the drilling equipment. Four such automatic controls have been perfected and have found practical use, these being the Hild differential drive, the

Halliburton drilling control, the General Electric automatic weight control and the Brantly hydraulic drilling control. Available space permits only brief descriptions of these somewhat complex mechanisms.

The Hild Differential Drive.—The Hild differential drive comprises a differential reduction gear, somewhat similar in design to that used in automobiles, together with two electric motors, all assembled as a unit which takes the place of the power plant normally provided. Controllers operating through a grid resistance, together with an



(*Courtesy of Oil Well Supply Co.*)

FIG. 123.—General plan showing relationship of Hild differential gear to draw works and rotary table.

indicating wattmeter and ammeter, supplement the main unit. Figure 123 illustrates the general arrangement of the Hild drive with respect to the rotary equipment.

As shown in Fig. 123, the drilling motor *A* is connected to one-half of the differential gear 3*a*, and also through gears 1, 3 and 6 and sprocket 7 to the rotary table, while the regulating motor *C* is connected to the other half of the differential 4*a*. The hoisting drum of the draw works is actuated by a chain drive from sprocket 8, attached to the central or floating shaft of the differential assembly. The drilling motor in a large unit suitable for deep drilling is a 75-hp. three-phase 60-cycle 440-volt motor, operating at a constant speed of 1,160 r.p.m. The regulating motor is smaller, generally 35 hp., and of the same type and speed as the drilling motor.

When gears 3*a* and 4*a* of the differential rotate in opposite directions at equal speed, sprocket 8 is stationary. When 3*a* and 4*a* rotate in opposite directions at different speeds, sprocket 8 rotates in the direction of the greater speed and at one-half the difference of their speeds. Thus the two motors *A* and *C* may run at or near full speed. By varying the speed of one or the other slightly the hoisting drum of the draw works can be slowly rotated backward or forward. The speed changes of the motors are affected by load variations. Motor *A* drives in the direction of lowering the drill pipe, while motor *C* drives in the opposite direction to hoist it. When the brake of the hoisting drum is released, the weight of the drill pipe, tending to rotate the drum, exerts a torque on motors *A* and *C* through the differential gear. This will tend to drive motor *A* somewhat faster. Motor *C*, on the other hand, will oppose this

pull and it will therefore slow down somewhat. The difference between the two motor speeds, thus developed, A being the faster, will permit the hoisting drum to revolve slowly in the direction of lowering the drill pipe. Motor C always tends to lift the drill pipe, even when it is descending, and the power load on motor C is always a measure of the unsupported weight of the drill stem.

The work of motor A during drilling, besides driving the rotary table, is always to lower the drill stem. When motor A has no frictional load, the effect of the descending weight of the drill stem is such as to produce a negative load, and motor A functions as a generator; that is, it serves as a dynamic, regenerative brake, returning current into the line and assisting in revolving the rotary table. When motor A thus serves as a regenerative brake, motor C takes energy from the supply circuit and motor A, operating as a generator, returns it. Apart from the losses, C and A balance. The kinetic energy of the drill stem in thus lowering itself will be transmitted to help turn the rotary table. Thus, when drilling, the output of both motors and the kinetic energy of the heavy drill pipe are all transmitted to rotate the bit.

When the bit is on bottom, the weight supported by the hoisting drum is diminished by the amount of the weight carried by the bit. Therefore the load on motor C is diminished, and, as the load decreases, its speed increases. Meanwhile, when the bit presses on bottom, motor A, rotating it, receives additional load and tends to slow down. The effect of motor C speeding up and motor A slowing down is to reduce the rate of movement of the hoisting drum, that is, the drill stem is lowered less rapidly. As the load on motor A increases, this downward progress of the drill stem approaches zero; and if the load on motor A becomes still greater, the drill stem will be slowly lifted.

The torsional load on the drill stem depends upon the bit pressure. Hence, with the differential control, the downward progress of the drill is regulated simultaneously and cooperatively by the pressure of the bit and by the torque of the drill stem. By slightly adjusting the motor speeds, a limiting pressure on the bit results, that is, the equipment may be adjusted to maintain any desired bit pressure irrespective of the material in which it operates.

It has been shown that the power input of both motors goes into the work of revolving the drill stem. A wattmeter ahead of both motors and indicating their combined loads will thus give a measure of the load on the drill pipe at any time. This indicating meter may thus be used to keep the driller constantly informed of the formation changes and condition of the bit. By using a recording wattmeter we may secure a graphic story of almost every phase of the drilling work, that involved not only in rotating the bit on or off bottom, but also in running in or coming out of the hole, making connections, etc. This record is not only helpful to the driller but is also of interest to the superintendent and engineers.

When the Hild drive is used, the driller's duties are exactly the same as before except during drilling. After the bit has been set on bottom, the apparatus set to maintain the desired bit pressure and the table started rotating at proper speed, the driller throws the hoisting-drum brake lever wide open and allows the automatic feed mechanism to take control. He is then free to leave the controls and attend to other matters, such as supervising mud circulation and incidental repairs to equipment. No human hand is needed at the controls until it becomes necessary to add a length of drill pipe or draw out the stem to replace a worn bit. The Hild drive is highly sensitive, accurate and quick to respond to variations in operating conditions. In addition to a straighter hole and fewer twistoffs, which result from more uniform bit pressure, it is claimed that the Hild drive makes better progress, with fewer interruptions in drilling; that power consumption is reduced; that there is less wear on the drilling equipment and that less skill and attention are required on the part of the driller. The

fact that it has as yet been developed to operate only with electric power has to some extent prevented its more widespread use. Though well adapted to the work of rotary drilling, electric power is not always available and many operators still prefer steam power.

The Halliburton Drilling Control.—Another device having automatic feeding and controlled bit pressure and drill-pipe torque as its objectives is known as the Halliburton drilling control. Like the Hild drive, described above, this device also makes use of a differential gear, somewhat similar to that used in the rear end of an automobile. It is a compact, chain-driven unit, mounted on heavy steel skids, designed for installation between the draw works and the steam engine, electric motor or internal-combustion engine used as a source of power. Several types are available, one or another of which is adaptable for use with any three- or four-speed draw works.

An understanding of the automobile differential gives a clear insight into the reason for using the differential as a means of controlling the weight on the drilling bit. The function of the differential of the automobile is to permit of a flow of power necessary for each of the two rear wheels, which are often operating at different speeds. In the same way, a division of the power and two available speeds are obtained from a single power unit when the differential drilling control is used, one of which is employed in operating the rotary table, while the other is applied to the hoisting drum of the draw works. The relative amounts of power apportioned to the hoist and rotary table depend upon the relative resistance encountered in each mechanism. The greater torque that can be safely transmitted to the bit is evenly and continuously employed. When the bit encounters a drilling load which its portion of the power will not handle, the other half of the differential applies power to the draw works and lifts the drill pipe and bit so that less bit pressure is exerted. As the resistance to the bit is relieved, the stem is again lowered and the bit continues making hole. The control is entirely automatic and the driller is relieved of all hand feeding.

The General Electric Automatic Weight Control.—Another device designed to provide automatic feeding and positive bit-pressure control has been developed by the General Electric Company. This comprises a two-speed motor-driven hoist, which operates on the dead end of the hoisting cable. An auxiliary resistor control and switch panel must also be provided. The action of the motor is governed by a weight indicator of the Martin-Decker type (see page 315) and is so designed that when the weight bearing on the bit is greater than an amount for which the apparatus may be set, the stem is automatically lifted off bottom. If the bit pressure is less than the maximum permitted, the apparatus automatically lowers the drill pipe at a rate which varies inversely as the bit pressure. The feeding and retrieving action of the device is thus automatically responsive to the weight imposed on the drilling bit and holds constant within close limits any weight set by the driller. By simple electrical control the automatic features may be disengaged and the hoist controlled by hand. It thus serves as a reliable, ever-ready stand-by substitute for the draw works. The unit may also serve as an auxiliary hoist, useful in rigging up and in making up drill-pipe and casing joints. A crank provided on the gear-unit drive shaft serves as a means of operating a jerk line.

The Brantly Hydraulic Drilling Control.—This device derives its power from the tension in the hoisting cable, which develops a torque on the drum shaft of the draw works, driving a small pump through a reduction gear. The pump impresses hydraulic pressure on water in its cylinders, and a manifold of adjustable valves controlling the rate of discharge of water from the pump governs the rate of descent of the drill column. Mechanically, the feed control consists of a double reduction gear and a six-cylinder double-acting pump, $1\frac{3}{4}$-in. bore and $2\frac{1}{2}$-in. stroke. The reduction gear and pump are built into a single unit that is mounted on skids so that it can be readily

moved about. A small steel water tank connected with the pump suction line is also mounted on the same skids. The pump discharge manifold, which includes the orifice valves for regulating the pump pressure and speed, is conveniently placed adjacent to the driller's position on the derrick floor. The low-speed shaft of the reduction gear is driven by a chain from a sprocket and clutch on the drum shaft or line shaft of the draw works. The over-all speed ratio is 250:1. Five orifice valves ranging in size from ¼ to 2 in. are incorporated in the pump discharge manifold.

Operation of the Brantly feed control is simple. The drill column is lowered until the bit is on bottom and then raised about 3 ft.; the drive clutch is engaged and the hoist brake is entirely released. The drill column is then lowered until the bit is on bottom, by opening the largest valve in the discharge manifold, thus permitting the pump to discharge freely. All valves are then closed except the one that provides the desired rate of feed, and the drill column is then rotated as in ordinary drilling practice. When the drill column is being lowered into or raised from the well or when a joint of drill pipe is being added, the drive clutch for the feed control is automatically disengaged. This device affords a wide range of feeding rate and operates without auxiliary power appliances. It is easy to control, is less expensive and yet accomplishes most of the objectives of the more elaborate mechanical and electrical drilling controls. However, it is not automatically responsive to changes in formation resistance as are the controls described in the foregoing sections.

HYDRAULIC-FEED ROTARY DRILLING EQUIPMENT

Careful study of the foregoing sections in this and the preceding chapter will, it is hoped, have impressed the reader with the importance of securing control of bit pressure in rotary drilling and will have suggested that, when mechanically controlled equipment is used, the necessary accuracy of control may be attained only through the use of special machinery of considerable complexity. Many of the difficulties that have been mentioned may be overcome and accurate control of bit pressures more readily be secured through the use of hydraulically controlled rather than mechanically controlled equipment. In the hydraulic method of control, such part of the weight of the drill stem as is not needed to create the necessary bit pressure is supported on one or more pistons operating in hydraulic cylinders and the bit pressure is controlled by regulating the hydraulic pressure within the cylinders. Control mechanism of fundamentally different character is required when this system of control is used. In such a system the superstructure of the derrick carries none of the drill-pipe load while drilling is in progress.

The Diamond Drill.—The hydraulic method of control of bit pressure was first applied in connection with diamond drilling. The diamond drill has been developed primarily as a means of taking cores rather than of "making hole," and the mechanism and cutting medium used are of a nature that require accurate control of bit pressure in order to avoid breakage or loss of diamonds and improper functioning of the equipment. For many years the diamond drill was considered inap-

propriate for use in drilling for oil, though it has found extensive use in prospecting for the metals, for coal and other nonmetallic products. Probably the chief reason for this belief was the fact that the earlier types of diamond drills were incapable of drilling holes exceeding about 2 in. in diameter—too small for efficient oil production in the event that oil was encountered. More recently the diamond drill has been further developed, and heavier models capable of drilling holes of larger diameter have been introduced and used to some extent in drilling for oil.

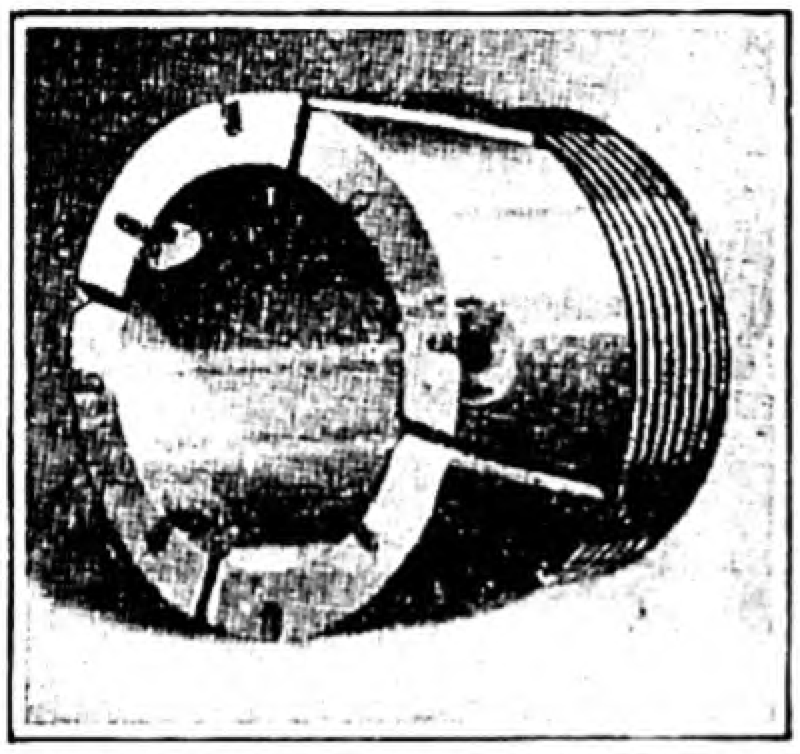


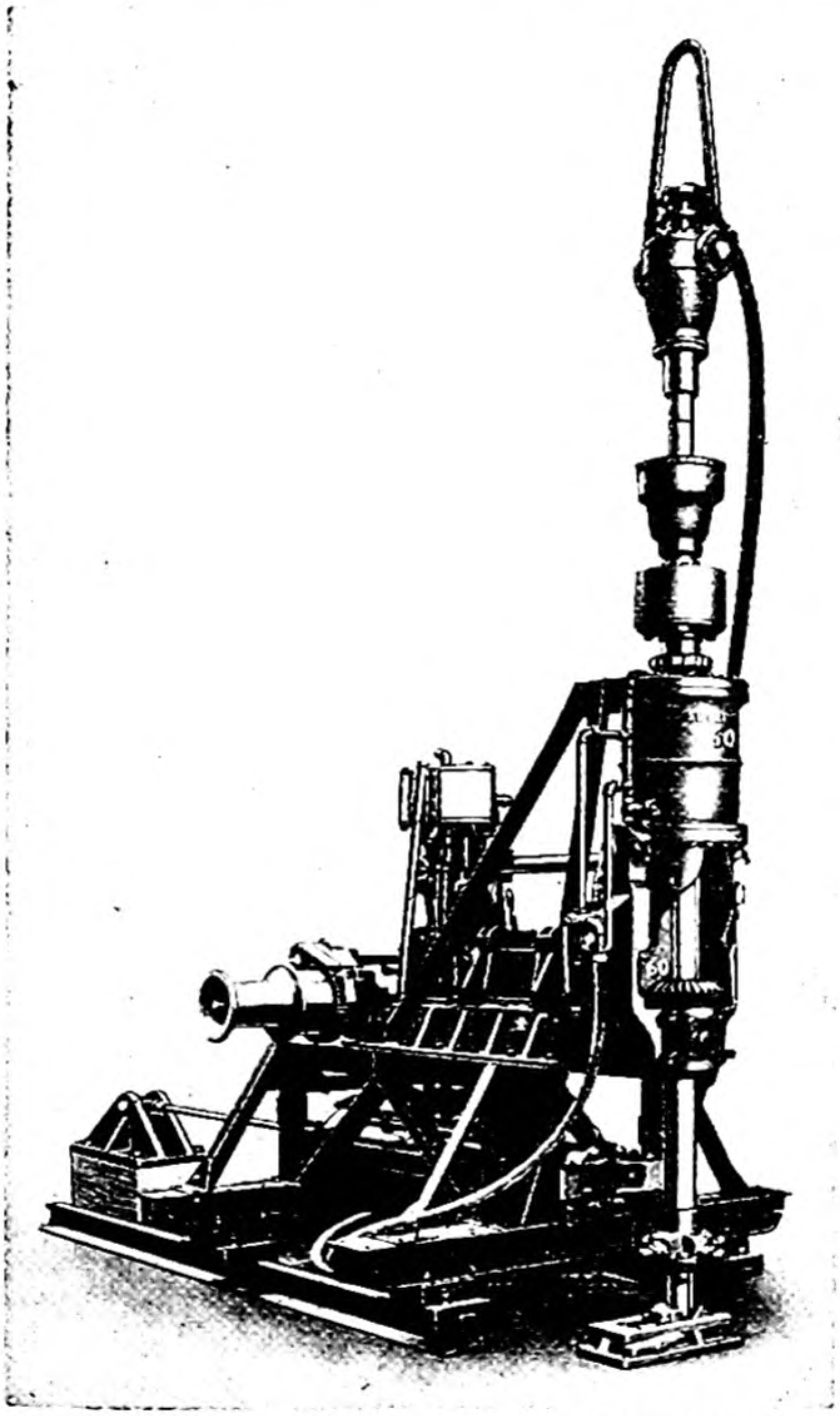
FIG. 124.—Diamond drilling bit.

The diamond drill is equipped with an annular steel bit, on the cutting edges of which are set a number of black diamonds (see Fig. 124). Owing to the high cost of "bort" diamonds, fragments of a hard, metallic alloy are sometimes substituted. The bit is mounted on the lower end of a core barrel, which in turn is supported by a stem made up of rods of flush-jointed square-threaded special steel tubing, furnished in joints 5, 10 or 20 ft. in length and of a diameter somewhat smaller than the bit. The drill stem used has a smoother surface—since there are no collars used—and is smaller in diameter than ordinary rotary drill pipe. For the deeper drilling characteristic of oil-field operations, rods $2\frac{3}{8}$, $2\frac{7}{8}$ or $3\frac{1}{2}$ in. in outside diameter are generally used.

The surface equipment includes the drilling machine, mounted on substantial steel or timber supports at one side of the position selected for the hole, a small reciprocating water or mud pump, a steam boiler, a water-supply tank, connecting steam and water piping and miscellaneous tools. A light derrick, tripod or mast is erected over the drilling machine to provide something to pull against in handling the column of drill rods which in a deep hole of large diameter may aggregate many thousands of pounds in weight. A sheave, over which the hoisting cable is passed, must be supported about 60 ft. above the mouth of the well, and "finger boards" for stacking 50-ft. stands of drill rod in a position slightly inclined from the vertical should also be provided. Where the overhead structure does not afford sufficient headroom to handle 50-ft. stands, shorter ones may be used; but the time required to draw out the rods and reinsert them in the well is increased. Time spent in handling rods is particularly important in diamond drilling if the usual form of bit and core barrel are used, since they must be run in and out with each 10 to 20 ft. of progress, depending upon the length of the core barrel.

The diamond drilling machine is assembled as a unit on a structural steel or timber frame (see Fig. 125) and comprises a vertical, twin-cylinder steam engine (or a gas engine may be used) which transmits power by a drive shaft and intermediate gearing, at either of two (sometimes three) different speeds to the drive rod. The drive rod has a chuck on its lower end for gripping the drill rod and extends up through the hydraulic cylinder. Enclosed in a suitable steel housing, on the upper end of the drive rod, are the ball-bearing supports which receive the thrust due to the weight of the column of drill rods in the hole and transmit it to the piston in the hydraulic cylinder. The column of drill rods extends entirely through the drive rod and is equipped on its upper end with a swivel, which provides a means of forcing water or thin mud fluid down through the rotating column of drill rods. This fluid is delivered under high pressure from the circulating pump through an armored, flexible

hose. A bail on the swivel affords a means of attaching the hoisting cable by means of which the column of rods may be lifted. This cable passes up over a sheave at the summit of the derrick or other superstructure provided, thence down to a power-driven hoisting drum on which the surplus cable is wound. In light machines intended for shallow drilling the hoisting drum is a part of the machine assembly and is driven usually at either of two speeds by gearing from the same engine that rotates the column of drill rods. For larger machines a more powerful, three-speed hoist is

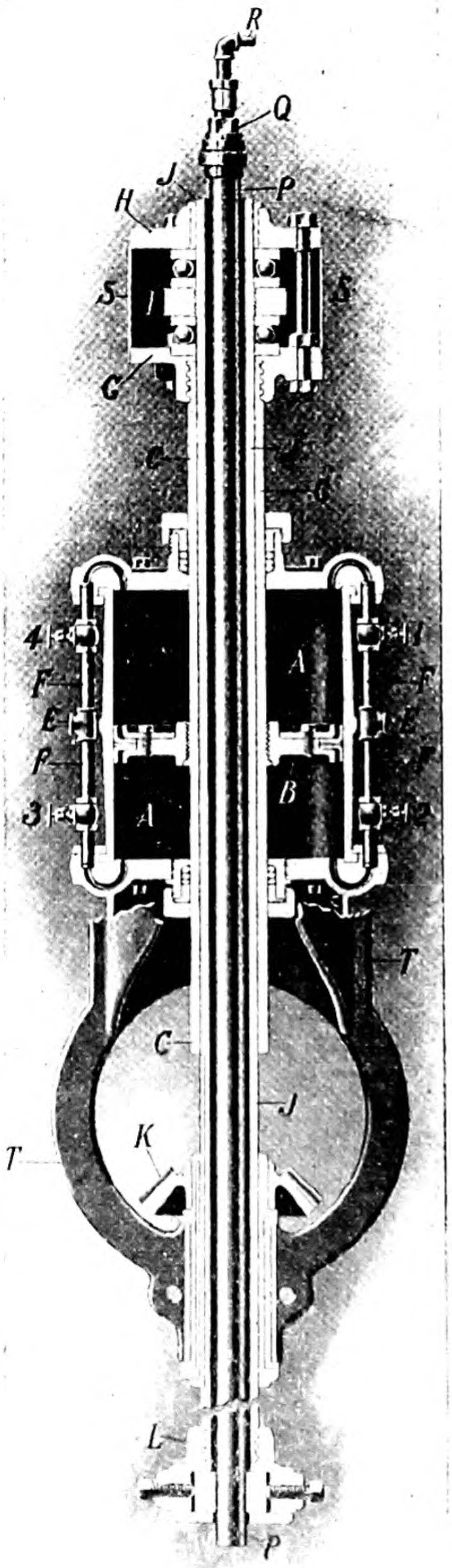


(*Courtesy of Sullivan Machinery Co.*)

FIG. 125.—Sullivan diamond drilling machine.

provided, mounted as a separate unit, and driven by a separate engine of sufficient capacity to handle long columns of drill rod or casing at appropriate speeds. An 11- by 11-in. twin-cylinder engine, developing about 150 hp., is used in driving the hoist. Safety clamps support the column of drill rods in the well at such times as it is disengaged from the drive-rod chuck or is not supported from the crown sheave. The entire machine may be moved back on floor slides or rails so that the hydraulic cylinder will be out of the way at such times as the column of drill rods is being withdrawn from the hole and uncoupled. Catheads assist in making up rod joints and in other light duties where power is required.

Figure 126 shows a vertical section through the hydraulic cylinder and drive rod. The column of hollow drill rods P, extending down to the core barrel and bit in the bottom of the hole, passes entirely through the drive rod J and is gripped by chuck L, which is screwed to the lower end of the drive rod. Power i applied to miter gear K, rotating the drive rod J to which it is splined. The drive rod rotates within the hydraulic piston rod C and may be raised or lowered with it, sliding through the miter gear, whose splines slide in grooves in the drive rod. The drive rod, in its upward or downward movement, carries with it the chuck and column of drill rods. Casting T supports the hydraulic cylinder and provides a lower bearing for the drive rod.



(Courtesy of Sullivan Machinery Co.)

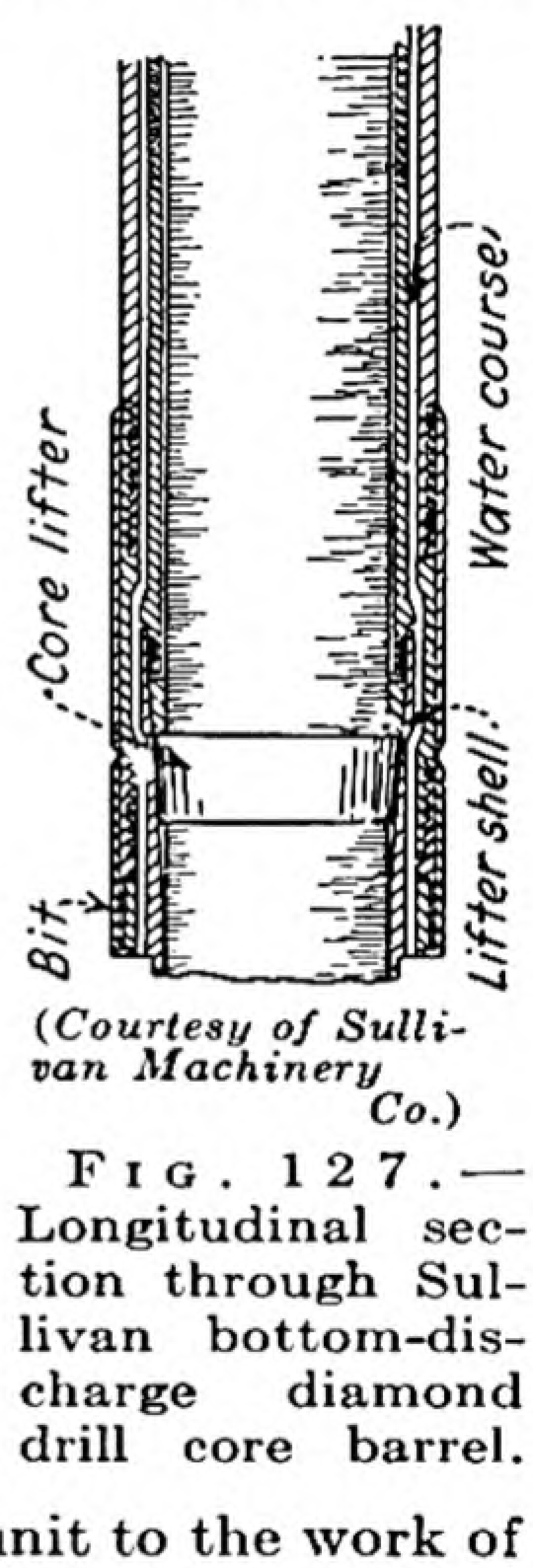
FIG. 126. Vertical section through hydraulic cylinder and driving mechanism of diamond drill.

The hydraulic cylinder is filled with water, both above and below the piston. By admitting water under pressure to one side of the piston, through pipe E or F, and releasing an equal amount from the other side, the piston—and with it the drive rod and column of drill rods—may be moved up or down. Adjustment of valves 1, 2, 3 or 4 controlling the flow of water into and out of the hydraulic cylinder permits of accurate adjustment of the rate of descent of the column of drill rods and the pressure permitted to bear upon the bit. In effect, the hydraulic piston and cylinder are equivalent to a hydraulic jack which carries the weight of the column of drill rods and yet allows it to revolve freely—a much more sensitive and delicate control than is afforded by the draw works of the ordinary rotary rig.

Again, with reference to Fig. 126, the drive rod J is supported by ball bearings I in housing S on the upper end of the piston rod C, two sets of ball bearings being provided, one to receive upward and the other downward thrust. The drive rod is thus caused to move positively up or down with the piston rod, yet permitting the former to rotate freely within the latter. The ball bearings operate in an oil bath, and the top and bottom of the housing, G and H, must be suitably reinforced and bolted together to receive the vertical thrust. A swivel Q permits of making connection at R with a source of water or mud fluid under pressure. This fluid, pumped down through the column of hollow drill rods, flows out into the hole through passages in the bit and rises to the surface between the drill rods and the walls of the well, carrying the pulverized drill cuttings to the surface and keeping the bit free of accumulated material.

The bit is of such form that it cuts a solid core out of the center of the hole, the resulting rock core being received and retained by a core barrel placed above the bit, between it and the lower end of the column of drill rods. The circulating fluid flows through a passage about the core barrel, as shown in Fig. 127. When a depth of hole slightly less than the length of the core barrel has been drilled, the bit, core barrel and rods must be hoisted to the surface and the core removed from the barrel. When a core is not desired, a fishtail, disk, cone or other form of rotary bit may be used without the core barrel. In this case, of course, the rods need not be withdrawn from the well until the bit becomes dulled.

In drilling, when such progress has been made that a new 10-ft. rod must be added to the drill column, this may be done by supporting the column of rods in the safety clamps, disengaging the chuck, unscrewing the joint at the lower end of the uppermost 10-ft. section, hoisting it out of the drive rod, coupling on the new rod, lowering it through the drive rod and connecting again with the column in the well. The column of drill rods is then again gripped by the chuck, the safety clamp is released and drilling resumed. In withdrawing the drill rods from the hole, they are uncoupled in stands usually five joints or 50 ft. in length, and stood on end at one side of the rig. The column in the well must be supported on the safety clamps while each joint is broken and stacked. The hoisting drum used in manipulating the rods is operated with two or three sets of gears in suitable combinations for hoisting the full weight of the column of rods from any ordinary depth, without the necessity of using double blocks. The hoisting drum is controlled by means of a powerful, wood-lined band brake, operated by a hand lever, and is adjustable for wear.



(*Courtesy of Sullivan Machinery Co.*)

FIG. 127.—Longitudinal section through Sullivan bottom-discharge diamond drill core barrel.

With the largest diamond drilling outfits, three pumps may be used, a clear-water duplex steam pump, 6 by 4 by 6 in., to operate the hydraulic feed, and two 10- by 5⅞- by 12-in. mud pumps to maintain circulation. The latter are operated by a 100-hp. steam engine, identical with that which drives the draw works. These two engines are cross-connected by means of a reverse clutch unit so that it is possible for the power to be applied either to pumping or hoisting as may be required in an emergency. This arrangement is particularly useful when hoisting the column of drill rods in a deep hole, as it enables the full power of the pumping engine to be applied in tandem with the hoist power unit to the work of hoisting; or, if one of the engines is shut down, emergency power for either the pumps or the hoisting drum is available from the countershaft.

Many styles and sizes of diamond drilling machines are available and have been widely used during years passed. Light diamond drilling outfits are used to some extent in coring operations in the older American oil fields as a means of securing information concerning sand conditions and residual oil content in introducing secondary recovery processes.[15] The largest size of diamond drilling machine available on the market has been used in drilling 4-in. holes at depths of 4,000 to 5,000 ft. in the Long Beach field of California.

The chief field of the diamond drill in the petroleum industry will probably be found in exploration and prospecting work, where geological information is desired rather than a well through which oil may be efficiently produced. Because of its speed and economy, the diamond drill offers what is often the least expensive means of determining whether oil is or is not present under a given location. Furthermore, it provides the geologist with an actual core of the rock formations penetrated, showing

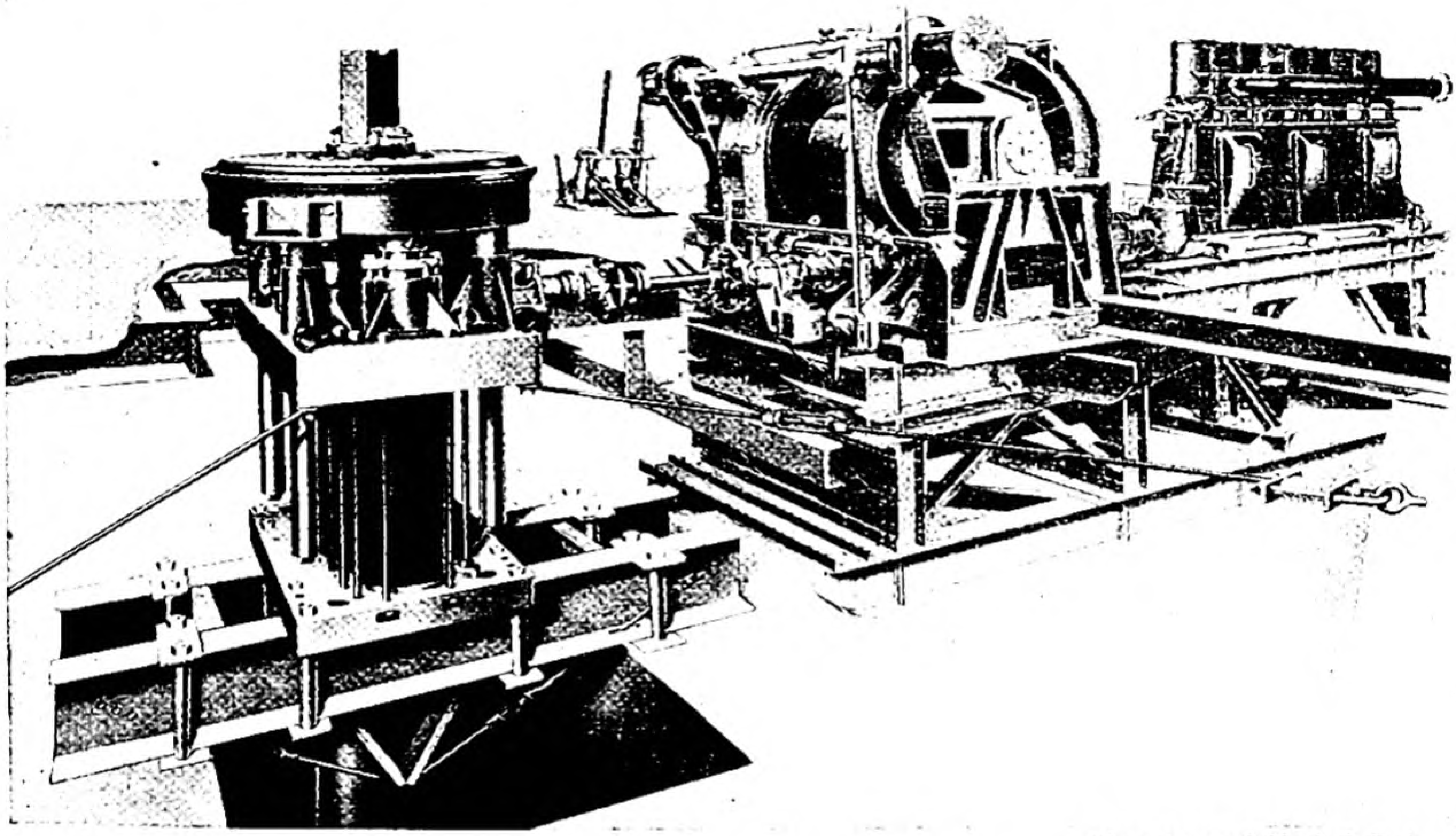
the material just as it occurs in place; and by proper measurements the cores may even be oriented with respect to the compass so that the amount and direction of the dip of the strata may be approximately determined. Such information is invaluable in prospecting for oil. And when it is remembered that in this work many dry holes must be drilled for every one that results in discovery of oil, it is apparent that the loss which results through inability of the small-diameter diamond drill hole to produce oil economically is, after all, a small matter. Furthermore, the diamond drill hole may be reamed to a 50 per cent greater diameter at small cost if production is secured. The primary purpose of the wildcat well is to secure information, not to produce oil, and if this principle is recognized, the diamond drill is well adapted.[8]

While it is generally conceded that the diamond drill is not well adapted to the drilling of oil wells in cases where a means of producing oil from a known oil deposit is the objective, there are notable exceptions which seem to indicate that under favorable conditions wells might be economically drilled for production by this method. For example, in the Panuco field of Mexico a diamond drill was used in the drilling of a well which was brought in with an initial production of 1,200 bbl. per day and subsequently successfully operated as a producing well. The well was drilled to a depth of 2,153 ft. and was finished with a minimum diameter of 3⅝ in. Gas pressures in excess of 750 lb. per sq. in. were encountered. The drilling speed, using the diamond bit in hard rock, averaged 75 ft. per day, but it is probable that double this footage could be maintained with a skilled crew and a longer core barrel than the 13-ft. barrel which was used. This well was completed in less than 90 days, though the average time of drilling to production in the district, with cable tools, is 5 months. The cost was about 60 per cent of the current contract price in the field. About 85 per cent of the core was extracted.[4]

Other wells have been drilled for oil with diamond drilling machines in the fields of Canada, Burma, California, Argentina and Venezuela, particularly in exploration work. Economy in casing is an important advantage of the diamond drill in comparison with other drilling methods, owing to the ability of the diamond drill to operate with smaller clearances. Forty per cent saving in casing requirements is claimed for the diamond drill and, largely because of this, it is asserted that wildcat wells can be drilled for 20 per cent less than by other methods. The capacity of the larger machines also compares favorably with other types of equipment. An operator in Venezuela has set 200 ft. of 16-in. casing, 1,000 ft. of 11¾-in. and 4,050 ft. of 6⅝-in. in 56 days. Continuous core was recovered in this well whenever desired.

The Hydril Hydraulic Feed Rotary Equipment.—Appreciation of the advantages of hydraulic control, through experience in diamond drilling, led Mr. F. Stone to attempt its application to the ordinary form of rotary drilling equipment. With the assistance of a capable mechanical engineering organization, the result of Mr. Stone's enterprise is the modern Hydril rotary drilling outfit now marketed by the Hydril Company. Accurate regulation and control of bit pressure have been the principal objectives in the design of this equipment. The designers and manufacturers have departed widely from the type of equipment that has become almost a standard in rotary drilling and have developed a mechanism that embodies many novel features. The most important feature, however, is the substitution of hydraulic control of the descent of the drill pipe during drilling for mechanical control. In addition to

this unusual feature, the Hydril equipment utilizes shaft-and-gear transmission for both the rotary table and draw works so that there are no exposed sprockets and chains. A special type of flush-jointed drill pipe is also available for use with this equipment, though the usual type with collars and tool joints may be used if desired. The rotary table and draw works are heavier than the usual rotary equipment, and the manufacturers have developed a special three-cylinder vertical



(Courtesy of Hydril Co.)

FIG. 128.—General view of several parts of the Doheny-Stone (Hydril) rig.

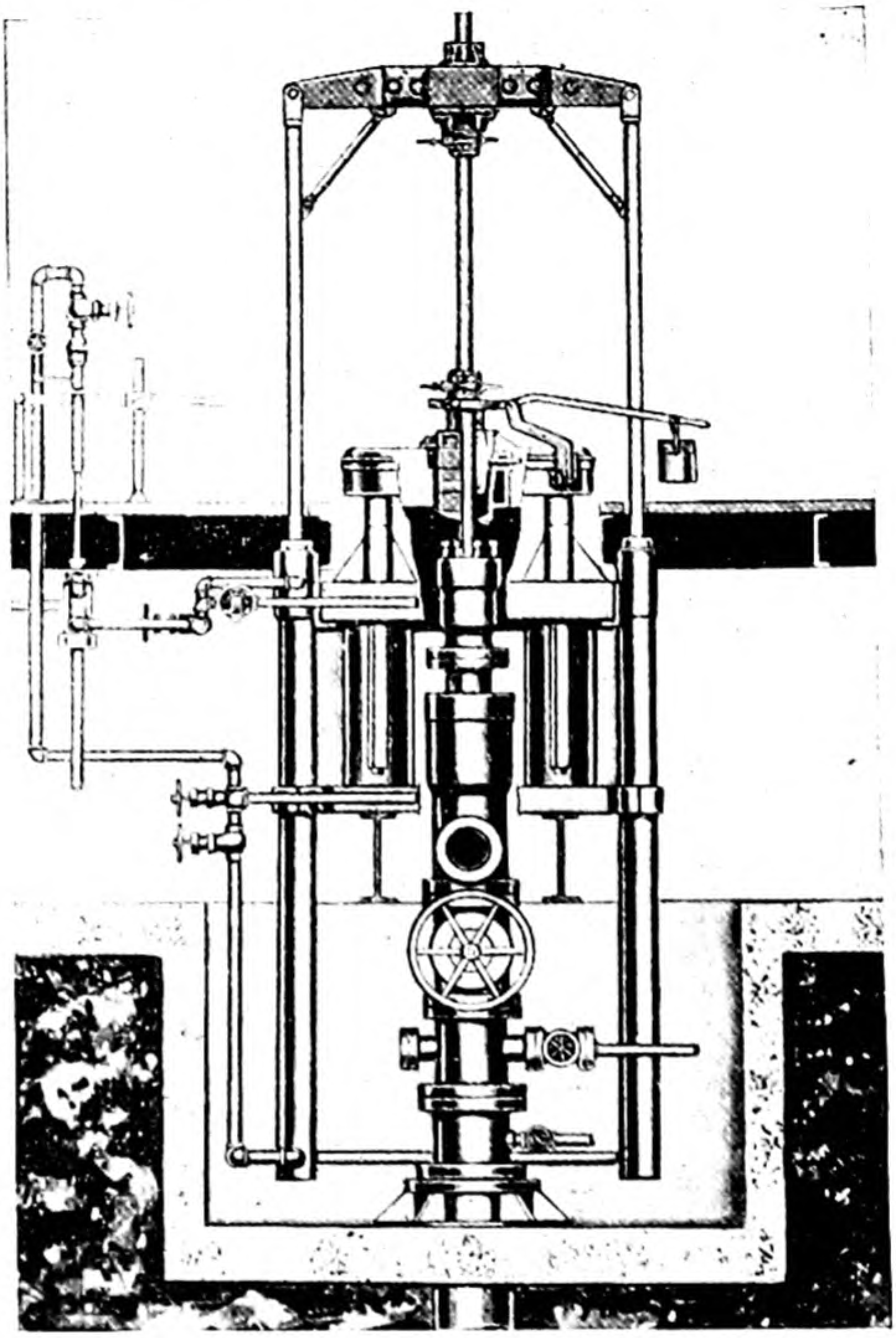
steam engine to drive it. The general appearance of the Hydril rig as a whole differs radically from that of the usual type of rotary. Figure 128 illustrates the general design and arrangement of the three principal units.

The rotary table is supported by two massive hydraulic jacks with long pistons capable of moving up and down through a distance of 5 ft. (in one model, 10 ft.) (see Fig. 129). The principal supporting element is a large steel base casting, which serves as a bottom cylinder head and is set upon and anchored to two heavy 20-in. I-beam structural members laid across the cellar. These I beams are reinforced by trussing and are securely anchored in concrete foundations. Two copper-lined and wire-wound steel cylinders serve as spacers between the stationary top and bottom cylinder heads. The cylinders are held in place by a number of heavy through bolts. The whole table is steadied in a vertical position by four radial tie rods extending to the four corner piers of the derrick. Heavy springs are introduced into these rods to ensure flexibility and to absorb shocks, as well as to eliminate vibration. Upon the upper cylinder head is mounted the bevel gear box through which the table is driven.

The reciprocating and rotating part of the rotary unit is supported upon two $6\frac{7}{16}$-in. piston rods, to the lower end of which 15-in. pistons are attached. The moving

part is guided, and lateral stresses are taken care of by four large-diameter guide rods attached to its base and sliding up and down with it through guide bushings in the top cylinder head.

The table is mounted upon roller bearings operating in heat-treated raceways. A hold-down ring is incorporated within the table and is also of roller-bearing construction and completely protected. The table gear is an internal spur gear, integral with the table. It is driven by a spur pinion, straddle mounted within the table base



(*Courtesy of the Hydril Co.*)

FIG. 129.—Hydril rotary table, showing special facilities used in pressure drilling.

upon Timken roller bearings. The gearing is completely enclosed. The pinion shaft is connected by a flexible coupling to the vertical gear-box shaft which in turn is integrally splined and slides vertically during the table movement through a driving sleeve, also Timken mounted, in the gear box. A bevel miter gear is mounted upon this sleeve and is driven by a similar gear on the drive shaft which passes out of the gear box and is connected through another flexible coupling and clutch to the transmission of the draw works.

The rotary table and the top cylinder head below the table are both fitted with bushings and slips so that it is possible to support three strings of pipe at once; one on the inner cylinder head, one in the table slips and one on the casing hook. Bushings and slips are provided in the table for gripping either Hydril flush-jointed drill pipe, or the usual square kelly. The largest size of Hydril table is capable of passing and

rotating 28-in. fishtail or disk bits and of handling drill pipe to the greatest depths yet attained.

The hydraulic pistons are actuated by a small, separately driven pump, and the hydraulic cylinders are of sufficient size to permit of handling weights as great as 150 tons at 800 lb. pressure.

When drilling is in progress, the column of drill pipe is at all times supported by the rotary table. The hoisting cable and blocks are used only in hoisting the drill pipe out of the hole when it is necessary to change bits. The table and hydraulic cylinders may support the entire weight of the drill pipe or such part of it as may not be necessary to maintain proper pressure on the bit. The drill stem is positively gripped with slips in the table so that it cannot move up or down relatively to the table. Hydraulic pressure within the hydraulic cylinders is controlled by valves on the pressure line from the pump, and on the discharge lines. These valves are conveniently located to the driller in his control position, and pressure gauges are connected in the water manifold to register the pressure applied. Just enough pressure is carried in the hydraulic cylinders to permit the table and drill stem to descend at any desired rate. A very sensitive control is afforded, it being possible to adjust for a feed of as little as 42 in. in 10 hr. or as much as 42 in. in ½ min., as well as all intermediate rates.

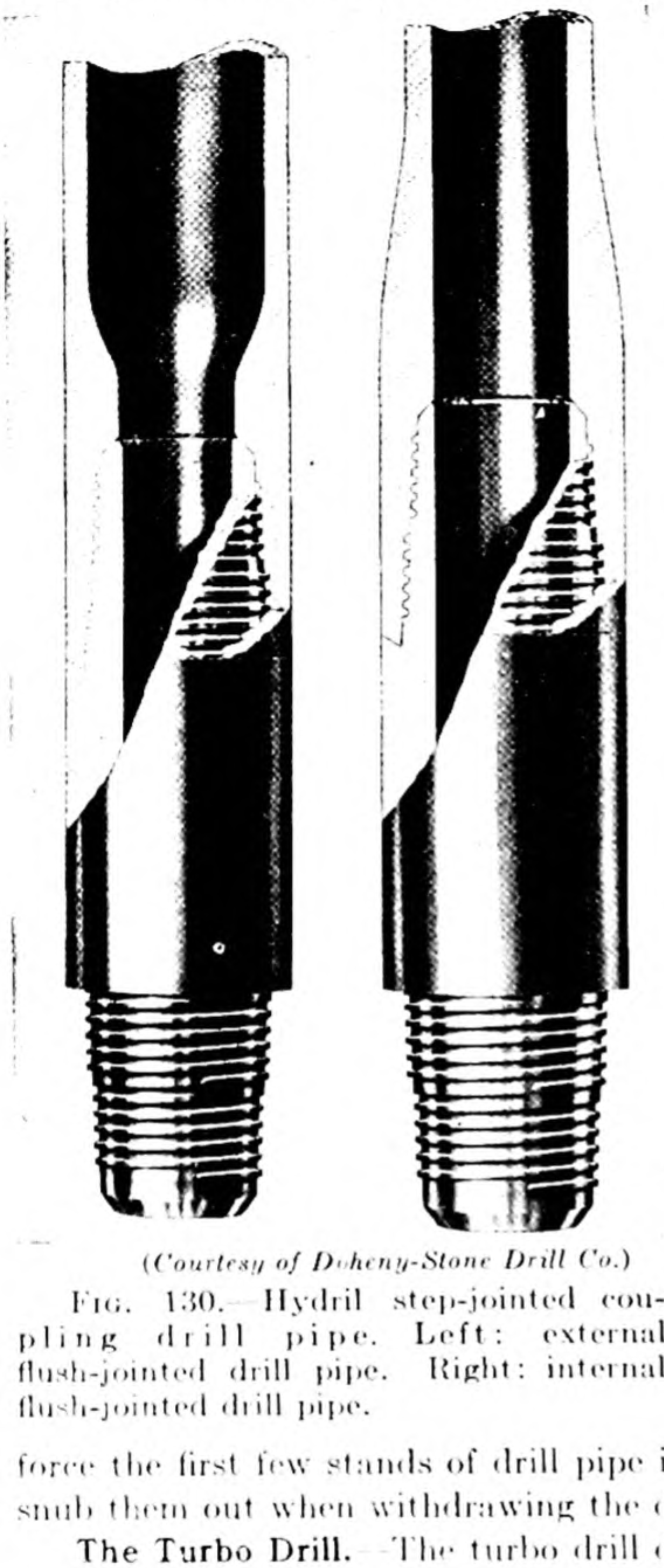
To enable the driller to have definite knowledge of the exact weight resting on the bit, a differential gauge is provided which indicates at all times the active unsupported weight of the drill pipe without the necessity of making any calculations. With such flexibility and knowledge of exact pressures applied—combined with simplicity of adjustment and accurate regulation of these pressures—a driller can control the bit almost as if it were on the surface. He can regulate it to suit the drilling conditions with a nicety not possible with any other means of control, cutting rapidly or slowly as his judgment indicates to be best procedure for the formations encountered.

The Hydril draw works is integrally mounted upon a solid and rigid cast-steel base, with all bearings secured in accurate alignment. The unit rests on a separate concrete base or special steel foundation, tied into the foundations of the derrick. As a result of this substantial foundation, there is less vibration noticeable in the derrick. The main drive is entirely geared. There are no open chains in any part of the equipment, and but one chain, completely enclosed, is used in the entire unit. This drives the cathead shaft and is in operation only during such times as the cathead is in use. The shaft drive from the engine comes into a three-speed transmission gear box, completely enclosed. The drive is taken from the gear box to the drum shaft through a herringbone gear and pinion, controlled by a positive jaw clutch, constituting the high-speed drive of the drum shaft. A low-speed drive is provided for the drum through planetary gearing at the opposite end so that with the two-speed drum drive and three-speed transmission, six speeds, covering a wide range, are available for hoisting. The hoisting drum is 24 in. in diameter, and brake drums are 46 in. in diameter with 10-in. faces. A brake-band truss surrounds the contact surface of the band, providing for accurate adjustment of the friction surface to the drum and for rigid and positive braking action. The drum and drum shaft are mounted on large-diameter Timken bearings and the brake drums are of pressed forged steel.

The Hydril three-cylinder vertical engine is also a novelty among oil-field engines. The three cylinders are each 10 by 10 in., and it is a double-acting piston-valve-controlled engine, with triple-throw crankshaft, developing 320 hp. at 320 r.p.m. on 150 lb. steam pressure. The engine is entirely enclosed in a metal casing and mounted on two heavy steel skids.

The Hydril flush-jointed drill pipe, illustrated in Fig. 130, is a development of the flush-jointed "rods" used in the diamond drill. As illustrated, the joints are internally threaded at each end and are joined by an externally screwed coupling. A

special form of square thread on a conical surface is used for convenience in quickly making up and disconnecting the drill pipe. Two threads are used, in step form, engaging as one. The external surface is a smooth cylinder with no projections to hang up on obstructions or gouge out the soft places along the walls of the well.



(Courtesy of Doheny-Stone Drill Co.)

FIG. 130.—Hydril step-jointed coupling drill pipe. Left: external flush-jointed drill pipe. Right: internal flush-jointed drill pipe.

For use with the Hydril equipment, the manufacturers have also perfected various other tools, some of them of novel design, including special drilling bits, reamers, and coring and fishing tools.

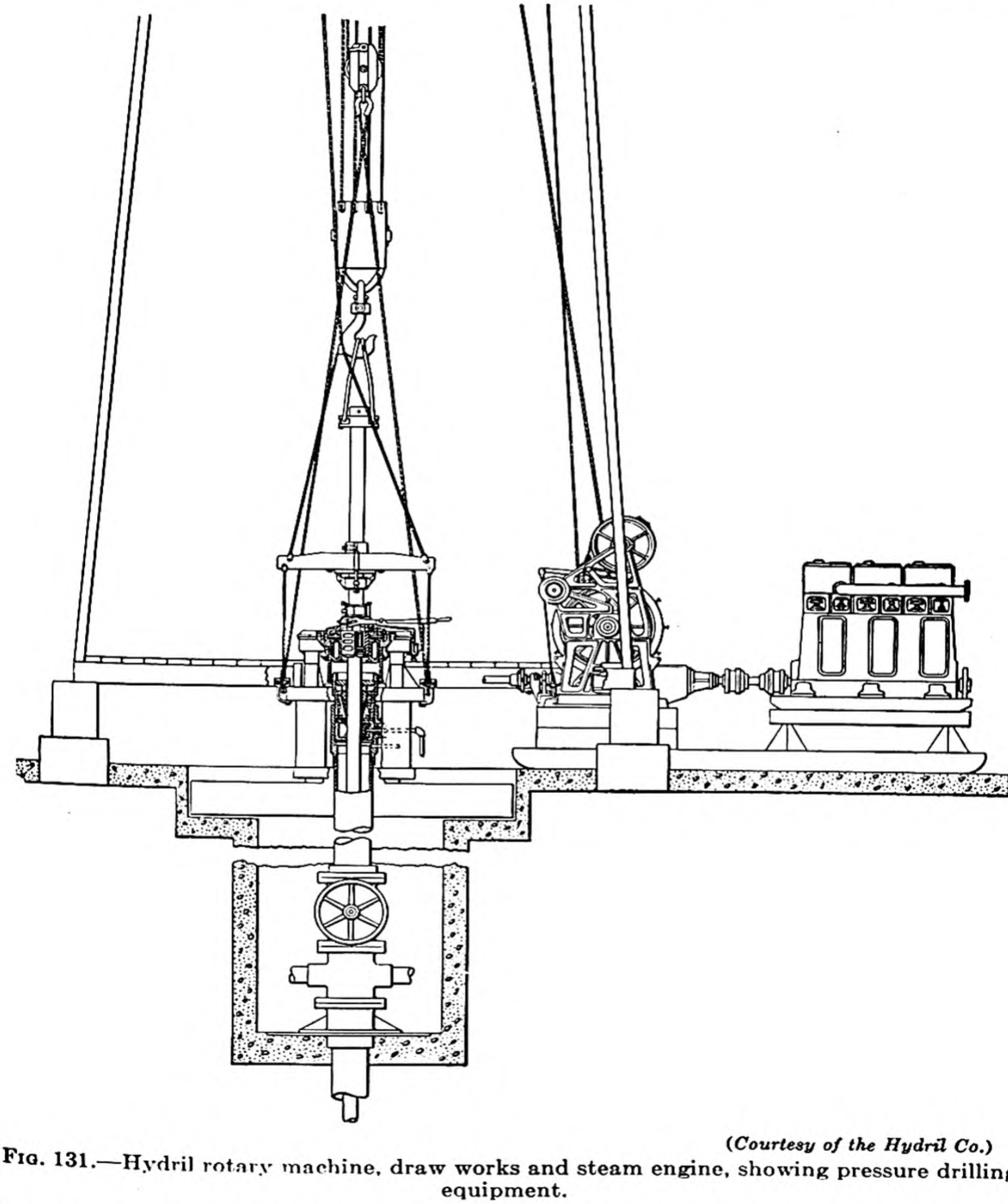
Some remarkable records have been made with Hydril equipment. In one case, in the Oklahoma City field of Oklahoma, a well was drilled to a depth of 6,400 ft. in 92 days, whereas the average drilling time for a well in this field to comparable depths with ordinary rotary equipment was 135 days. The average well in the Oklahoma City field required 66 sets of cone cutters in drilling to 5,200 ft., while the well drilled with Hydril equipment required only 40 sets. The Doheny-Stone equipment has also achieved some unusual records in the deeper fields of California, notably in the Kettleman Hills and Ventura fields, where it has been in competition with standard types of equipment.

The Hydril equipment is well adapted to drilling in very high pressure formations or to dealing with heaving sands and shales characteristic of high-pressure formations. By closing in the space about the drill pipe with a suitable packing head or blowout preventer and releasing the drilling fluid through a valve under back pressure, it is possible to add many hundreds of pounds of pump pressure to the static pressure afforded by the drilling fluid. Special pull-down equipment is used in the derrick to force the first few stands of drill pipe into the well against the pressure and also to snub them out when withdrawing the drill pipe (see Fig. 131).

The Turbo Drill.—The turbo drill designed by M. Capelushnikov and developed and used to some extent in the Russian oil fields is unique in that the drill stem does not rotate with the drilling bit. There is therefore no necessity for the swivel and rotary table. The turbo drill is rotated by the pressure of the circulating drilling fluid on a hydraulic turbine enclosed in a tubular element mounted on the lower end of the drill pipe. The latter serves only to conduct the fluid to the turbine and to apply pressure to the bit. Suitable gearing is provided for reducing the high rotational speed of the turbine to that desired for the bit. The mud pump thus becomes the source of power in operation of the drill, and the power developed depends entirely upon the capacity of the pump.

Figure 132 presents vertical and horizontal sections through the turbine rotor and gear-reduction mechanism. The upper end of the shell A is screwed on the

lower end of the nonrotating drill pipe through which the drilling fluid is delivered. The fluid is given rotational deflection by the stationary guide vanes B before it enters the curved vanes of the turbine rotor C. Discharging down around the reduction-gear



(*Courtesy of the Hydril Co.*)

FIG. 131.—Hydril rotary machine, draw works and steam engine, showing pressure drilling equipment.

box by way of the annular space D, the fluid enters the rotating tube E to the lower end of which the drill is attached. The fluid is discharged into the well through holes in the bit and lifts the drill cuttings to the surface in the usual way. The turbine is of the Jonvalle or Curtis hydraulic type, its power being transmitted through the shaft F and reduction gears G to the vertical tube E which emerges through a fluidtight

bushing and gland. The entire reduction gear is hermetically sealed so that the circulating fluid does not have access to its accurately machined gearing. End pressure on the rotating elements is taken up by ball bearing *J* while the gear assemblies rotate on ball bearings *I* and the turbine shaft rotates on ball bearing *M*. Lubricating oil is fed through the turbine shaft and reduction gearing to all bearings by the pressure of a piston actuated by fluid pressure in the head of the turbine unit. From one to three reduction-gear units may be used, affording a range of rotational speeds for the bit of from 25 to 370 r.p.m.

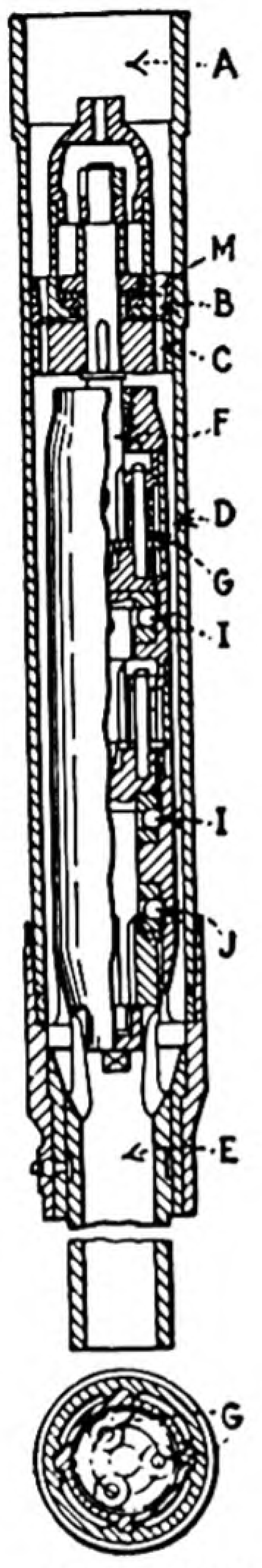


FIG. 132. Capelushnikov turbo drill.

It is claimed that the turbo drill makes straighter holes than is usual with rotary equipment and affords more efficient utilization of power. There is no frictional loss resulting from pressure of rotating drill pipe against the walls of the well. There are fewer twistoffs of the drill pipe and a lighter one may be used. The equipment is less expensive since the costly rotary table and swivel are eliminated. Owing to the absence of rotating parts in the surface equipment, the accident hazard is reduced.

ROTARY CORE-DRILLING AND SAMPLING DEVICES

One of the principal objections offered to the use of the hydraulic rotary system of drilling during the earlier years of its development was that it provided no adequate samples of the formations penetrated. Logs of wells assembled on the basis of mechanical reactions of the equipment and inspection of finely pulverized returns brought to the surface by the circulating fluid were found to be undependable. Owing to the hydrostatic pressure developed by the long column of heavy mud fluid, oil- and gas-bearing sands were drilled through and sealed off without their presence being made known. These objections to the use of the rotary equipment have now been largely removed by the development of dependable rotary coring devices.

Early efforts in this direction were only partly successful in that the devices used were unreliable and the cores secured were often imperfect. One of the first and simplest coring devices, more properly called a "sampling device," consisted of a piece of casing about 3 ft. long and 3 to 8 in. in diameter, on the bottom edge of which V-shaped notches or teeth were cut either by machine methods or with the aid of the oxyacetylene torch. The teeth thus formed were usually "set" alternately to one side and the other, like the teeth of a saw, to maintain clearance on both the inside and outside. Attached to the lower end of the drill stem, this device is rotated into the formation under moderate pressure. As the core barrel is revolved and the teeth cut into the formation in the bottom of the well, the loosened material is forced upward into the barrel and there retained by frictional contact. A hole bored through the side

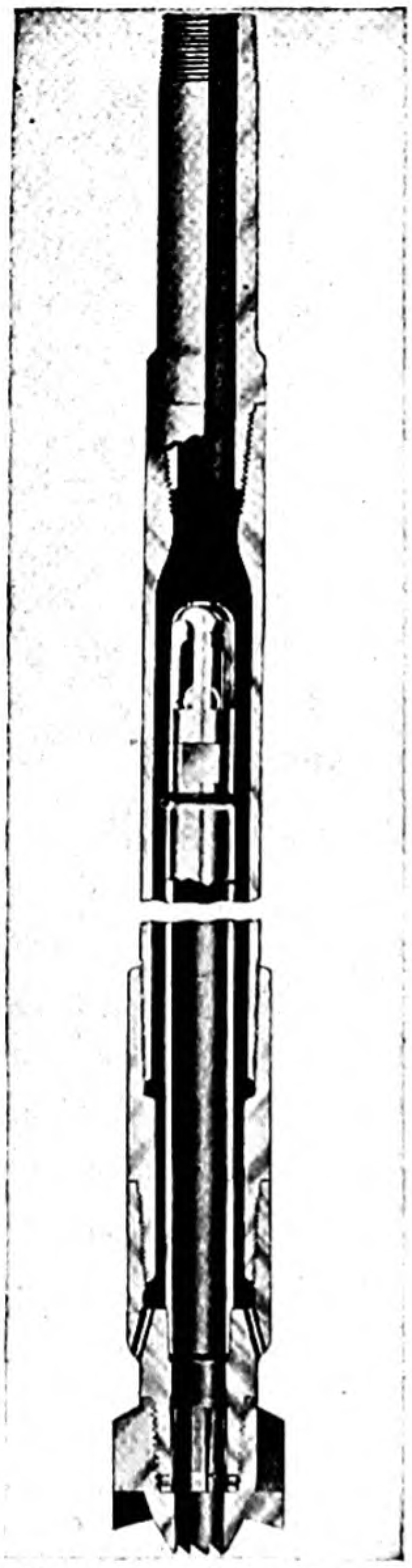
of the tube near the top permits escape of the imprisoned mud fluid. Toward the end of the coring operation with this type of sampling device, the bit pressure and the rate of rotation are increased, with the purpose of "burning the core into the barrel," collapsing and overheating the teeth of the barrel until they close in on the lower part of the core. The heat developed is in many cases sufficient actually to fuse some of the constituents of the core. An alternative plan consists in raising the drill stem a foot or two and dropping it on bottom, with the purpose of bending the teeth inward to prevent the core from falling out of the barrel as the tool is withdrawn to the surface. Soft material is usually sufficiently compressed to be retained without difficulty, but hard rocks are likely to be loose in the barrel. When taking cores in hard formations, some drillers have followed the practice of dropping small pieces of cast iron into the drill stem. These metal fragments settle on top of the core in the barrel, and, on raising and lowering the barrel a few times on the core, they become lodged between the core and the barrel so that the material is effectively retained.

Another early type of core-sampling device, also in the form of a short section of pipe, supported on the lower end of the drill pipe, was simply dropped or spudded into the formation with the purpose of punching out a sample. Another style of early core barrel was of the auger type, a tube with a pointed cutting lip being mounted on the lower end of the drill pipe and slowly rotated into the formation. It excavates soft material in much the same manner as an ordinary post-hole auger. In drawing out the tools, the lip prevents the sample from falling out of the barrel.

These early types of rotary core drills, although simple in construction and low in cost, had many disadvantages. They were capable of securing only short, broken, distorted and otherwise imperfect cores, usually contaminated with mud, the material being often altered by overheating. On being withdrawn to the surface, the cores were difficult to extract from the core barrel without breaking. The hole formed had usually to be reamed out to gauge, and fishing jobs were common, owing to breakage of the tool or to its becoming fast in the hole.

Difficulties experienced with these primitive coring tools eventually led to the introduction of the double-barrel core drill now used almost exclusively. Later development has resulted in the perfection of this type of core drill until, by its use, it is now possible to take long and fairly continuous cores in rocks of almost any character. The different core drills of this type may be roughly classified into two groups, one using a scraping type of bit appropriate for use in comparatively soft formations, while the other, utilizing roller cutters, is designed for hard-rock drilling.

For soft and moderately hard formations, a core drill of the type illustrated in Fig. 133 may be used. This consists of two concentric tubes with an annular passage between for drilling fluid, the fluid being discharged through holes just above the cutter head. The outer tube consists of several parts coupled together with screw connections. The upper connection provides a means of attaching the tool to the drill stem or drill collar. Below this, the outer barrel of seamless-steel drill pipe, 10½ ft. long, supports the lower sub and the latter is screwed to the cutter body. The replaceable cutter head is screwed on the lower end of the cutter body, and in an internal groove between the two the core catcher is supported. The inner tube is screwed at its lower end into an interior recess in the top of the cutter body. A valve of the ball-and-disk-seat type, with a cage or "crown" to hold the ball in position over the seat, is mounted on the upper end of the inner barrel. The cutter head, the sub and cutter body are made of chrome-nickel steel, especially heat-treated to secure proper hardness and wearing qualities. The cutter head is faced with a hard-facing fusion metal, such as stellite and, where extreme hardness is required, as in the taking of long cores in hard formations, fragments of tungsten carbide are embedded in the hard-facing metal. Cutter heads protected in this way yield about four times the footage secured from ordinary hard-faced heads.



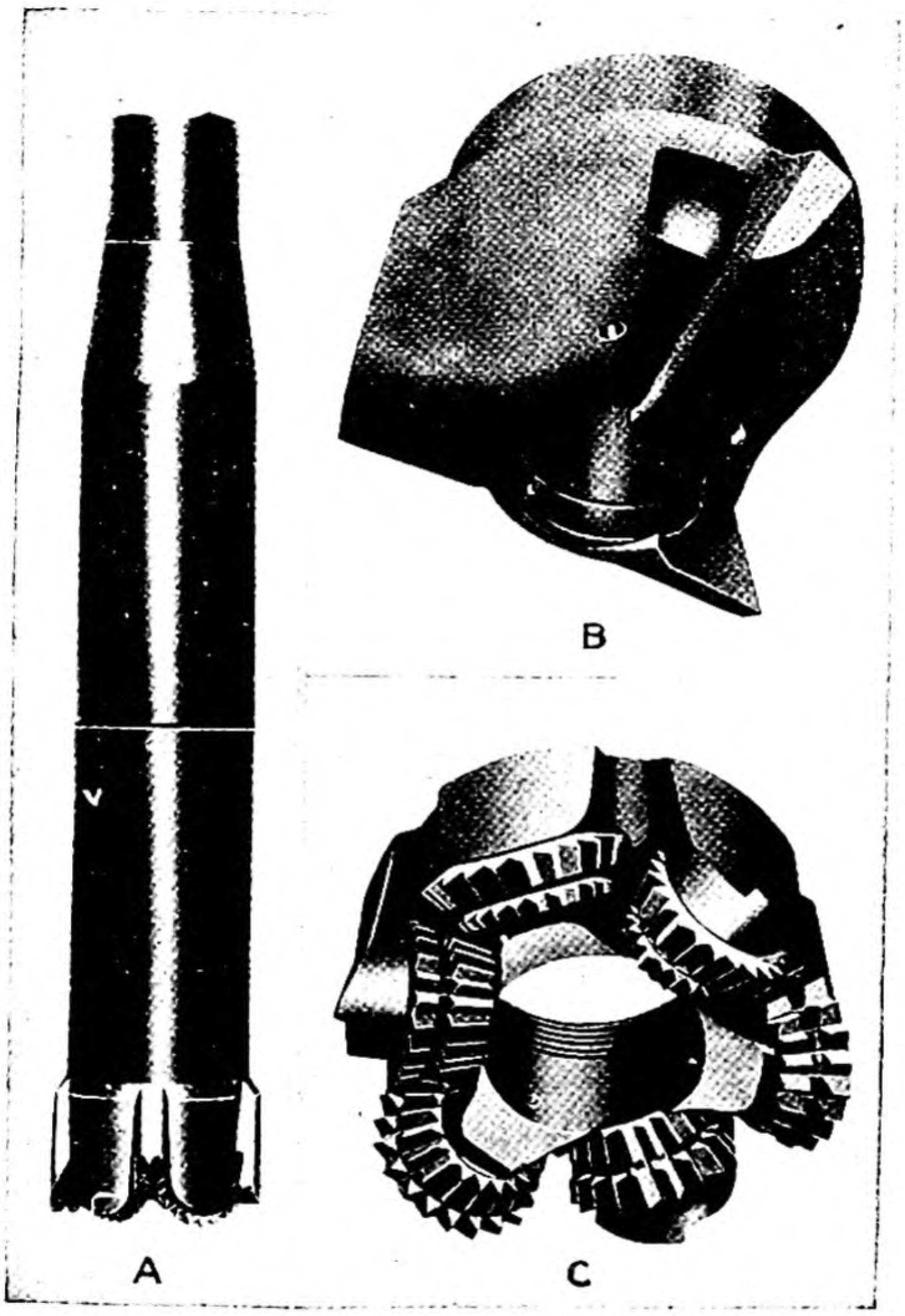
(*Courtesy of Elliott Core Barrel Co.*)

FIG. 133.—Elliott rotary core drill.

In operation, the tool is lowered to bottom, attached to the lower end of the drill stem, either with or without a drill collar, and mud fluid circulated until the density of the fluid throughout the well has been equalized and accumulated drill cuttings have been removed. As light a fluid should be used as conditions in the well permit. The tool is then rotated on bottom at the rate of 30 to 40 r.p.m. with moderate bit pressure. A 10-ft. core is usually cut at one operation, and under very favorable conditions, with a 21-ft. barrel, cores as long as 20 ft. may be secured. Cores taken with this type of barrel range from 1¼ to 4 in. in diameter, depending upon the size of the hole and that of the drill pipe on which the tool is designed to operate. As the core is cut, it is forced upward past the core catcher into the inner barrel. Mud fluid imprisoned in the inner barrel above the core is forced out through the valve at its upper end into the circulating fluid channel between the inner and outer barrels. A sheath of clay, which forms around the core, serves to protect it against frictional contact with the inner barrel. When coring is completed, the speed of the mud pumps is reduced and the rate of rotation of the stem is increased to facilitate breaking off of the core. As the tool is lifted off bottom, the core catcher grips the core in the barrel and prevents it from falling out. After reaching the surface, the joint between the cutter body and lower sub is broken and the inner barrel unscrewed from the cutter body. The valve at the upper end of the inner barrel is removed, and the core forced out of the barrel with the aid of a specially designed core puncher. The tool drills the hole to full gauge so that it is unnecessary to ream after coring.

Under the conditions presented in the California fields, where the rocks to be penetrated are comparatively soft, an average of about 70 per cent of the formation

cored is secured with this type of barrel. A new core head costs about $40 and the cost per foot of core recovered averages about $4. One operator in the Long Beach field of California cored continuously from 5,000 to 7,000 ft., averaging about 133 ft. per day. Twenty-seven tungstite-protected cutter heads were used, or an average of 74 ft. of coring per head. In the Gulf Coast region of the United States the cost of 10-ft. cores is reported to range from $42 for depths of less than 2,000 ft. up to $140 at a depth of 8,000 ft.



(Courtesy of Hughes Tool Co.)

FIG. 134.—Types of core drills. *A*, Hughes core bit equipped with hard-formation cutter head; *B*, Hughes core bit, soft-formation cutter head; *C*, Hughes core bit, hard-formation cutter head.

The roller type of core drill, used in coring hard and moderately hard formations, is illustrated in Fig. 134. The assembly of the outer barrel is very similar to that of the coring tool described in the preceding paragraphs. The inner barrel is in this case equipped with a "time-limit valve," which is adjusted to remain open for a predetermined time against the pump pressure, permitting circulating fluid at first to flow through the inner barrel, flushing out any drill cuttings that may enter the barrel during its descent. A stiff grease, which gradually yields to the pump pressure, eventually permits the valve on the upper end of the inner barrel to close, the time of closing being indicated by change in speed of operation of the circulating pumps. The cutter head in this type of core drill, furnished as a unit, ready to screw on the

body of the tool, is equipped with six pairs of conical cutting rollers which revolve on hardened ground pins, welded to the forged and heat-treated cutter head. The conical roller cutters are so spaced that the bit head rotates true with the center of the core; hence there is no eccentric motion tending to break up the core. Mud fluid is discharged under pressure from the space between the inner and outer barrels through six holes, one above each pair of cutters. The cutters are patterned after and operate in much the same way as the cutters on Hughes cone bits, described on page 262. Core bits of this type are operated at the same rotational speed and with the same bit pressure recommended for use with Hughes cone bits. The core catcher is so designed that it does not grip the core until the tool is lifted off bottom. Ten-foot cores of granite have been taken with this tool, cutting at the rate of 2 ft. per hr. Complete cores (*i.e.*, little or no loss) have also been taken through beds of hard sandstone, sandy lime and anhydrite, these being the harder types of rocks encountered in oil-field drilling. Sizes in this type of core barrel range from 1¼ to 7 in.

Difficulty sometimes encountered in taking cores with the rotary equipment may be due to a crooked stem, causing the tool to operate eccentrically, or to improper consistency or insufficient volume of the circulating fluid, so that cuttings are not carried away rapidly enough and become embedded in the core. Pieces of iron or steel in the bottom of the hole, the result of earlier breakage of tools or well equipment, will usually cause trouble if present. Hard "shells" may cause rapid dulling of cutter heads. Excessive bit pressure or too rapid rotation may result in breakage and "burning" of the core or damage to the cutter head.

Wire-line Retractable Core Barrels.—Operators are often reluctant to take cores with conventional core barrels in wells drilled with rotary tools because of the cost and time lost in making an extra round trip with the drill pipe. This objection is met by the use of retractable core barrels that may be used at any time without withdrawing the drill pipe from the well. The wire-line core barrel is used in conjunction with special drilling bits, usually of the roller, demountable or bladed types, in which an assembly comprising the drilling elements of the central part of the bit is removed by a wire line lowered through the drill pipe, at such time as it is desired to take a core. The core barrel is then forced down the drill pipe by circulating fluid under pump pressure until it is seated in a recess in the drilling tool, where a locking device may be provided to hold it in cutting position. Drilling is resumed and, after the requisite length of core has been cut, the barrel with its contained core is retrieved by lowering through the drill pipe on a wire line, an "overshot" designed to engage a mandrel or "spear head" on the upper end of the core barrel. The central portion of the drilling bit is then restored by the same means and regular drilling is resumed.[1,3]

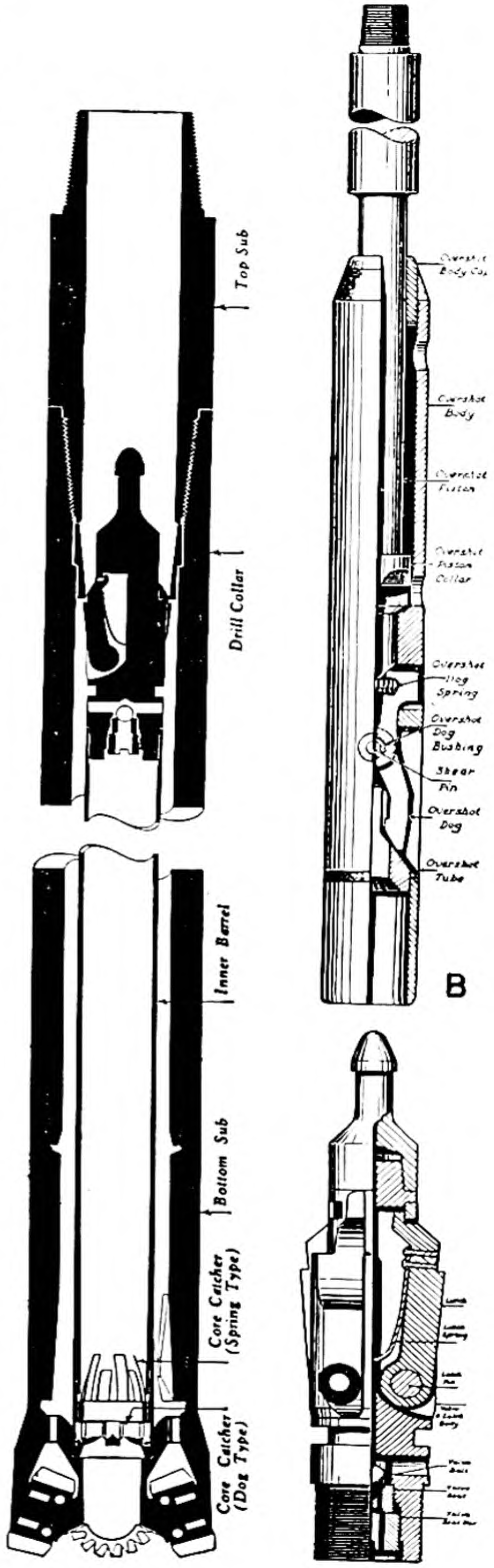
Figure 135 illustrates a retractable coring tool of this type. When the operator desires to take a core, the kelly is disconnected from the drilling column and set aside, and a special overshot lowered through the drill pipe on a wire line to retrieve the center barrel assembly of the drilling bit. The inner core-barrel assembly is then dropped in the drill pipe, the kelly replaced and the mud pump operated slowly until the core barrel reaches the drilling tool, when it automatically locks in working position and coring can be conducted in the usual manner. A slight increase in pump pressure is noted when the core barrel reaches its position in the drilling tool. After the core is cut, the core barrel is retrieved with the aid of the overshot and the center bit assembly is pumped down the drill pipe until it latches in working position. Special fishing tools are available for releasing the overshot when, for any reason, it is impossible to pull the core barrel free of the drilling tool. Special designs of retractable core barrels featured by different manufacturers include various latching devices, a spring mechanism for projecting the cutting element of the core barrel a

little in advance of the cutting wings of the drilling bit, and special valve construction to release fluid and cuttings from the barrel when receiving the core. One barrel utilizes pump pressure alone to hold the cutting elements in working position and requires no latching mechanism. Well-surveying equipment may conveniently be lowered through the opening in a wire-line core bit when the drilling assembly is removed.

Retractable wire-line core barrels permit of drilling full-gauge holes while coring, and at speeds almost as great as with ordinary drilling tools. One can core or not, as circumstances warrant, and with minimum loss of time and expense in withdrawing drill pipe. Continuous cores as large as 2½ in. in diameter and 10 ft. long may be secured by this means.

Pressure Core Barrels.—Conventional core barrels of the types described in the foregoing sections are capable of securing samples of the formations penetrated, inspection of which will indicate satisfactorily their lithologic properties. However, such cores are of doubtful value in estimating quantitatively the fluid content of the formations from which they have been taken. In the process of cutting cores with rotary equipment, the circulating fluid, jetted against the bottom of the well under high pressure, tends to flush out the native rock fluids from the pore spaces of the rock ahead of the cutting tool, substituting drilling fluid for any oil, gas or connate water that the rock may contain. Any gas that remains trapped in the core or that is in solution in oil will tend to expand as pressure is reduced on withdrawing the core barrel toward the surface; and, in expanding, the gas will expel a large part of the liquid from the core. Thus, the residual fluid found in the core when it reaches the laboratory will be of little value in estimating the percentages of oil, gas and water originally present in the pore spaces of the formation cored.

Pressure core barrels are designed to cut a core from the formation exposed in the bottom of the well and imprison it in a gastight container within the core barrel, so that no fluids may escape from the core while it is being removed from the well and transported to a test laboratory for inspection under conditions that permit of accurate determination of the fluid content. The pressure core barrel is patterned, generally, after the conventional rotary core barrel, with the addition of an inner tube with valves at each end and a

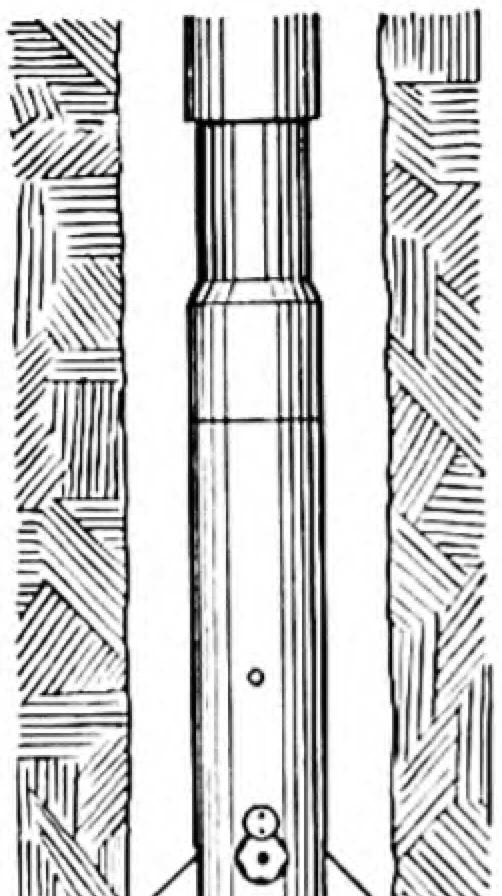


A C

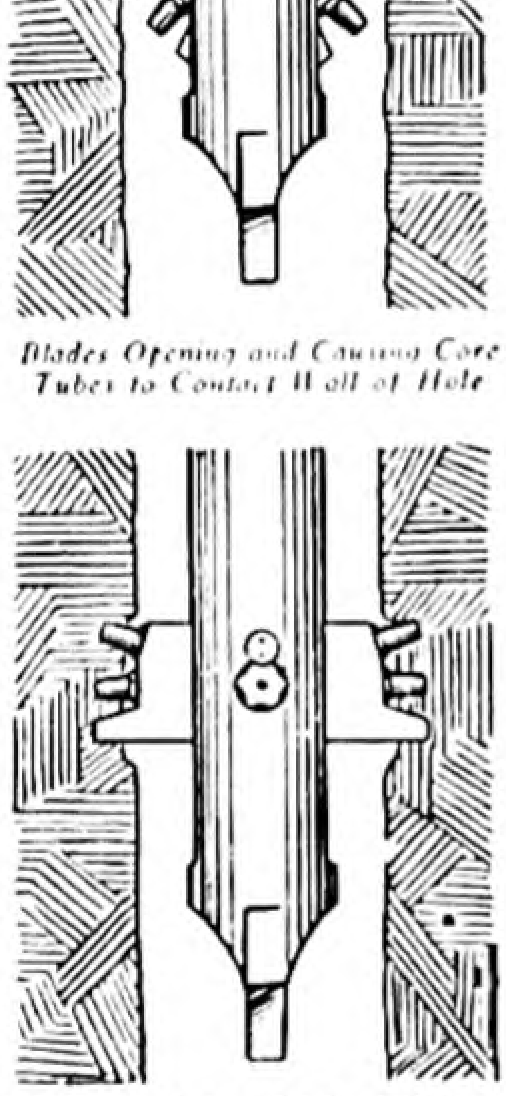
(Courtesy of Globe Oil Tools Co.)

FIG. 135.—Wire-line retractable core barrel. *A*, assembled coring tool; *B*, overshot assembly; *C*, valve and latch assembly.

mechanism for closing them, which receives the core and preserves it free of all external influences. Two core barrels of this type have been developed but they are costly, their mechanisms are complex and they have not as yet attained more than limited use in field practice. However, successful applications have been made in which cores have been taken and sealed at the bottom of the well under pressures as great as 2,700 lb. per sq. in. The laboratory technic involved in measuring and releasing pressure and in analyzing the fluid content of formation samples taken with the pressure core barrel is also complex. Although the pressure core barrel affords a solution for the problem of preventing escape of fluid from the core after it is cut, it does not prevent flushing of the native fluids from the rock in the path of the drill before the core is cut.[13,14]



Blades Opening and Causing Core Tubes to Contact Wall of Hole



Tubes Forced into Wall of Hole and Filled with Sample of Formation

(Courtesy of Baker Oil Tools, Inc.)

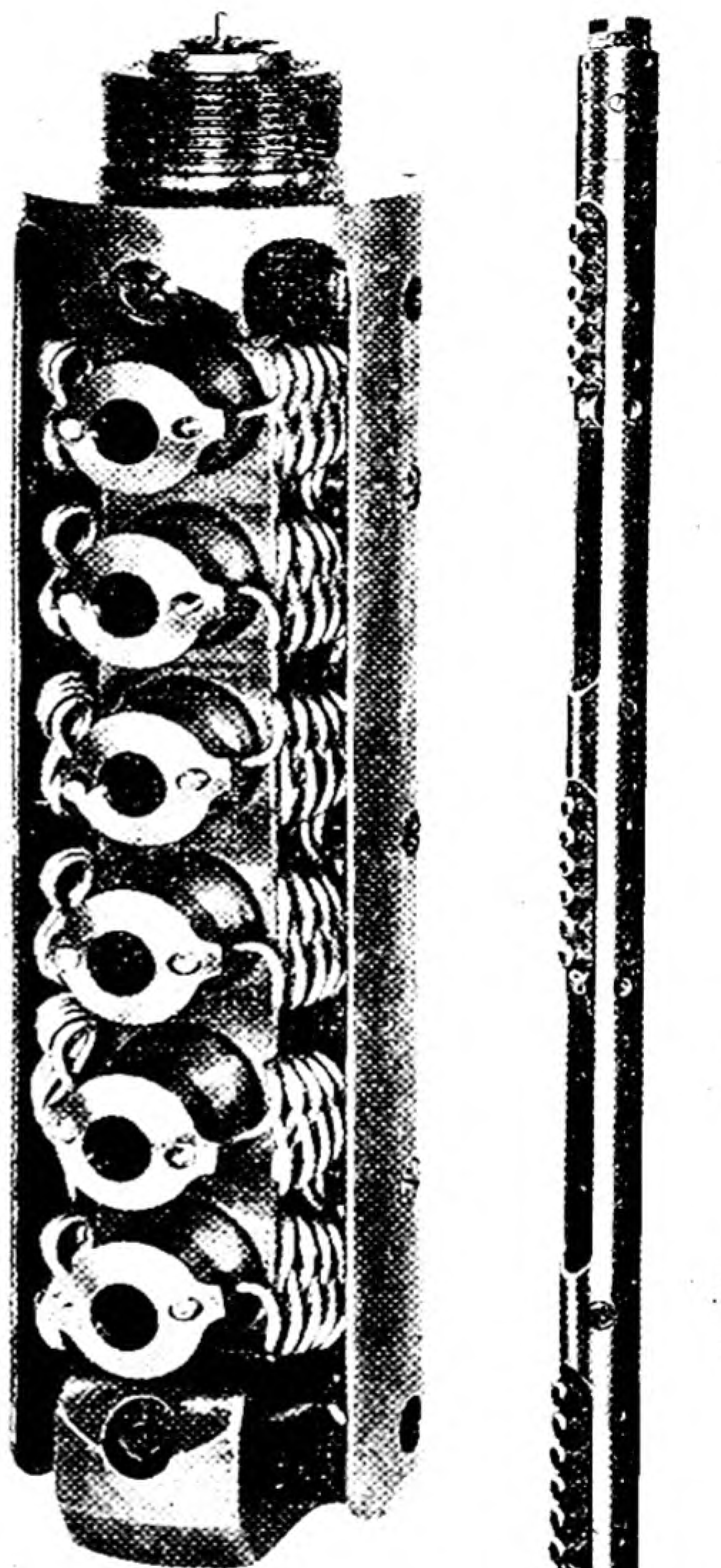
FIG. 136.—Hydraulically actuated wall sampler.

Side-wall Coring Devices.—The coring tools, thus far described, are designed to secure samples of the formation exposed in the bottom of a well, during the progress of drilling. At times, however, it will be desired to secure core samples from a formational interval that has previously been penetrated by the drill and in such cases resort may be had to devices capable of securing samples of the material exposed on the wall of the well. For example, a producing formation may have been drilled rapidly with no effort made to secure core samples during the course of drilling. Later, perhaps as a result of an electrical survey, interest may attach to a particular interval and it becomes advisable to secure wall samples for laboratory study. If cable tools are in use, chip samples may be secured with the aid of a special type of drilling bit that is deflected against the wall of the well at the elevation from which samples are desired. Two more positive types of side-wall coring tools are available for this purpose, one actuated by hydraulic pressure and the other by explosive force.

The Baker Hydraulic Wall Sampler.—This tool is identical in construction with the Baker hydraulic wall scraper, except that special blades are used, each of which supports a pair of core-taking tubes (see Fig. 136). The tool is lowered into the well on the end of a column of drill pipe, with the blades in collapsed position. When suspended in the well at the point where samples are to be taken, pump pressure is applied to the circulating fluid in the drill column, depressing the hydraulically actuated piston within the tool and expanding the blades outward and upward against the wall of the well. After the blades are in contact with the wall, and with pump pressure maintained, the weight of the column of drill pipe is slowly and steadily applied to the tool. This causes the blades to penetrate the wall and forces a core of the formation into each of the sampler tubes. The core tubes are made of a special tungsten alloy steel, selected to provide a tough, hard-cutting edge, heat-treated to increase these qualities. The outside of each tube is beveled from cutting edge to shoulder, to provide additional strength and to enable the tube to pull out of the formation easily. The inside of each tube is tapered, being smaller at the cutting edge than at the base. This allows the core to expand slightly as it enters the tube and prevents the core from falling out while coming out of the hole with pump pressure

released and the core blades in collapsed position. Cores taken with this device may be as long as $2\frac{1}{2}$ in. and $1\frac{1}{16}$ in. in diameter: large enough for the usual laboratory tests. The core tubes may be used repeatedly if care is taken in their application.

The Schlumberger Side-wall Sample Taker.—This device comprises a heavy steel body containing 6, 12 or 18 small core-cutting tubes that can be projected individually into the wall of the well from small "guns" with the aid of a powerful explosive. Constructed somewhat like a gun perforator, the tool is lowered into the well on a multiconductor armored cable, the guns being fired electrically from surface controls. The diameter of the well should be at least 5 in. The sample tubes are made of special alloy steel, $3\frac{3}{4}$ in. in diameter, and present a sharp cutting edge to the formation (see Fig. 137). Being open at both ends, there is no tendency to crush or compact the formation. Each tube is attached to the body of the tool by two substantial coiled steel springs, so that they are retrieved from the wall of the well with their contained cores when the tool is withdrawn from the well. Each charge is fired separately at whatever depth in the well the operator may desire. Usually the intervals to be cored will be determined by inspection of an electrical log. The method is rapid and comparatively inexpensive, it being possible to secure 18 cores within a period of 3 hr. or less. The cores are about $\frac{3}{4}$ in. in diameter and from $1\frac{1}{2}$ to $2\frac{1}{2}$ in. long. The core-cutting tubes normally penetrate several inches into the wall of the well, beyond the influence of the sheath of clay deposited on the walls by the drilling fluid. Hence, the cores are less contaminated and their fluid content is likely to be more nearly representative of the native formational fluid than is the case with cores taken at the bottom of the well with conventional coring tools.[7]



(Courtesy of Schlumberger Well Surveying Corp.)

FIG. 137.—Gun-type side-wall sample taker. Left: detail of six guns. Right: assembled tool for taking cores.

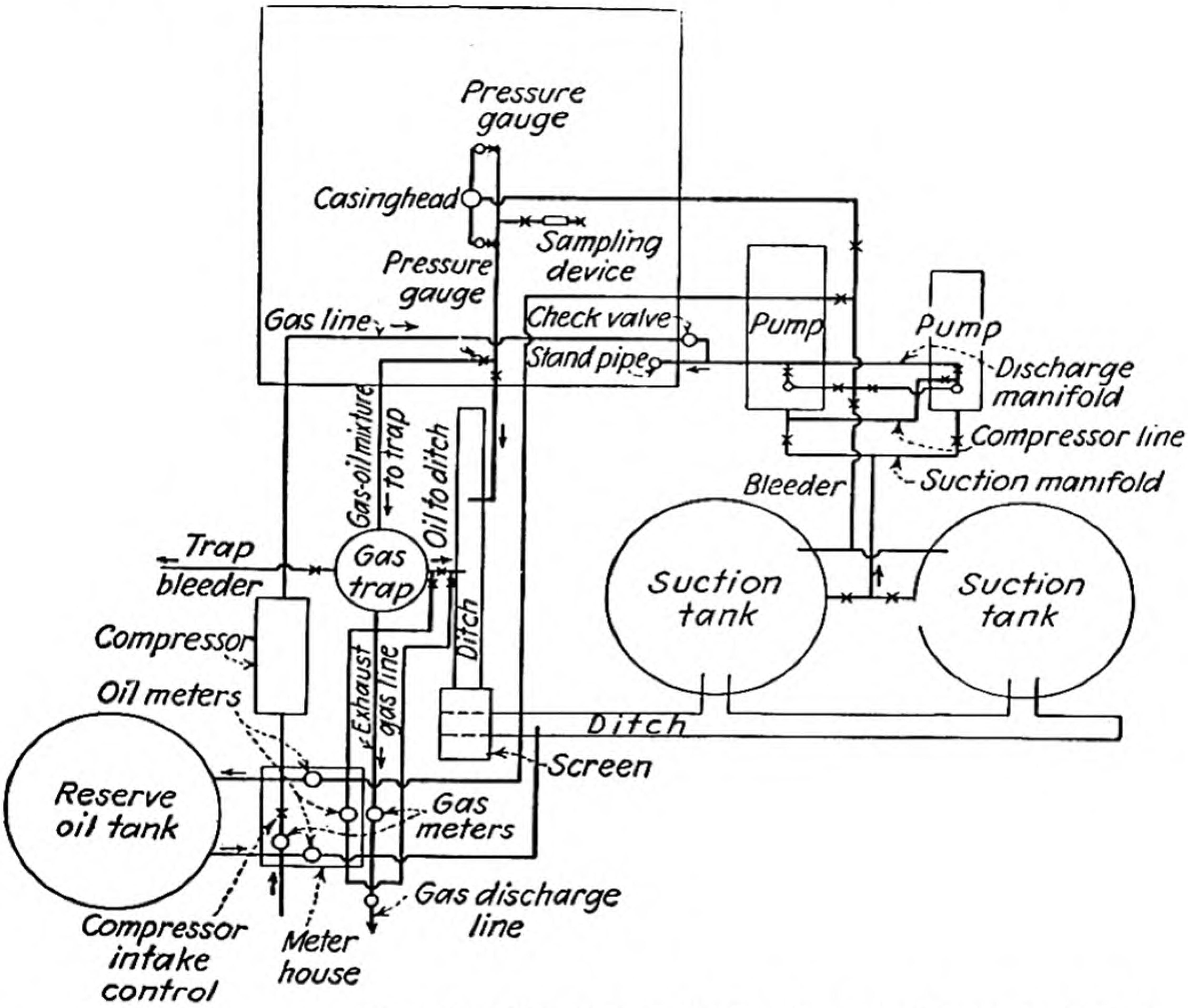
Side-wall Samples Obtained in Gun Perforating.—It has been observed that the gun chambers of gun perforators often contain fragments of formation from the wall of the well when withdrawn to the surface after a casing perforation operation. Contraction of the gases created by the explosive immediately following their full expansion apparently creates a suction that draws rock fragments shattered by the bullets back into the shells from which the projectiles have been fired. The amount of formational material thus provided is ordinarily insufficient in quantity and too badly shattered for quantitative tests, but it is fairly clean and not badly contaminated with clay from the drilling fluid.[11]

REDUCED-PRESSURE DRILLING

In drilling through oil- and gas-bearing formations by the rotary method with clay-laden drilling fluids, the walls of the well are left sealed with deposited clay. The density of the drilling fluid is such that the normal hydrostatic pressure developed by the depth of the well exceeds the formation pressure and tends to force water and clay through the walls of the well into the surrounding reservoir rock, often to such a degree as seriously to impair the subsequent productive capacity of the well. In a high-pressure formation, we may expect subsequent flow of oil and gas to force most of the clay and water back into the well when it is allowed to produce, but in a low-pressure or partly depleted reservoir this may be only partly realized and the well perhaps never attains its full potential capacity. To avoid this difficulty and restrict sealing of the productive formation with drilling fluid, a method of well completion involving what is called "pressure drilling" has been developed. This involves drilling through the producing formation under reduced hydrostatic pressure, realized by substituting aerated water or oil for the usual water-base clay-laden drilling fluid. The hydrostatic pressure developed on the producing formation is so far reduced by this practice that gas and oil may flow into the well from the formation while it is in process of drilling, thus precluding any possibility of sealing the walls of the well by deposited clay.

Conventional rotary drilling equipment may be used in reduced-pressure drilling, with the addition of certain auxiliary equipment necessary to safeguard the well against possible blowout and to provide for injecting compressed gas into the drill column and trapping the gas from the well fluid after it has circulated through the well and returned to the surface. Figure 138 presents a diagrammatic sketch showing arrangement of the surface equipment, where a mixture of crude petroleum and natural gas is substituted for the ordinary drilling fluid. Oil is drawn from the slush pit by the circulating pump and forced through a mixing chamber where it is mixed with gas under slightly greater pressure, thence through the standpipe, hose, swivel and drill column to the bottom of the well. A casing head with two side outlets is provided, with suitable control valves on each, while a packing device above the point of discharge of drilling fluid fits snugly about the drill pipe, yet permitting it to revolve freely, and confines the drilling fluid to the controlled outlets at the casing head. A round kelly, which passes without difficulty through the packer, may be used, though other forms of packers designed for use with conventional square or hexagonal kellys are also available. A back-pressure valve in the lower end of the drill column is also provided as further insurance against backflow. From the well

head, the drilling returns flow through lead lines to a gas trap, where gas is separated from the oil, and the oil then flows into a cone-bottom tank or over a vibrating screen, where suspended detrital material is separated from the oil before it is returned to the slush pit for further circulation through the well. A cellar, somewhat deeper and larger than normal, permits of placing the packer and control valves below the derrick floor.



(*After R. Winterburn in Trans. Am. Inst. Mining Met. Eng.*)

FIG. 138.—Sketch showing surface arrangements for reduced-pressure drilling.

In operation, the outlet from the well is throttled by partly closing the control valves or interposing a "choke" in the lead line between the well head and the trap, thus imposing moderate back pressure on the well. Pump pressure is applied on the circulating system and the amount of gas entering the drill column is adjusted so that the pressure maintained at the bottom of the well is somewhat lower than that in the formation in which the bit is drilling. Thus, a moderate differential pressure is maintained which encourages fluid to enter the well, adding itself to the circulated gas and oil entering the well through the drill column. A high rate of flow of fluid into the well must be avoided; otherwise the walls may cave; but the rate of flow through the annular space must, of course,

be sufficient to carry the drill cuttings to the surface. In adding a new length of drill pipe or drawing out the drill column, danger of blowout is avoided by replacing with oil all gas in the circulating system. Gas and oil entering and leaving the well are separately metered or gauged, so that the amount of fluid entering the well from the formation may be calculated. Input and exit pressure are also continuously recorded, so that the bottom-hole pressure may at all times be estimated.

In addition to the primary objective of avoiding clay deposition in and on the walls of the well through producing formations, reduced-pressure drilling offers definite advantages in formation testing and sampling (see page 561) and in increasing drilling speed and bit footage. The method is, however, somewhat more costly because of the additional equipment required and time and labor spent in rigging up. In some formations, difficulty is experienced in tendency of the walls to cave.

Reduced-pressure drilling has been successfully employed in drilling through producing formations in the Kettleman Hills and Dominguez fields of California and in the Fitts pool of Oklahoma. The results have indicated that wells may be completed by this method with greater productive capacity than when drilled by conventional methods, and that reduced-pressure drilling affords a facility in formation testing not otherwise possible. In the Fitts pool, drilling speed was increased 24 per cent, and 41 per cent better footage was obtained with the rock bits employed. Drilling cost increased 50 per cent, however.[19,21,23]

Formation Testing in Reduced-pressure Drilling.—In the routine of pressure drilling, it is possible at any time to determine the productive capacity of the formations that have previously been penetrated by the drill. Thus, if after drilling into a promising oil sand a test of its productive capacity is desired, it is only necessary to hold the bit just off bottom and gradually reduce the volume of oil entering the drill column, simultaneously increasing the amount of circulated gas. Finally, all input of oil is cut off and, if the oil sand yields oil and gas to the well, its production is gas-lifted to the surface and can be directly gauged and metered; or, if the oil is in sufficient volume and pressure, the well may flow it unaided to the surface through the annular space. Repeated testing at different depths shows, by difference, the productive capacity of the intervening formation. Thus, the commercial status of the well is known at all times. Where water is produced with the oil, as is common near the productive limits of the reservoir, the percentage of water obtained in successive formation tests will be a dependable guide in restricting penetration to a depth at which oil with a minimum of water "cut" will be obtained.

Formation Sampling in Reduced-pressure Drilling.—In drilling with oil as the circulating fluid, pressure drilling affords a means of

securing formation samples uncontaminated by clay and susceptible of more accurate identification. Thus, the formations penetrated may be more accurately logged than when a clay-laden drilling fluid is used. Mechanical coring has also been successfully conducted under conditions imposed by pressure drilling.

DIRECTIONAL DRILLING

Control of the course of a well during the process of drilling is of vital importance in attaining the desired objective. Every well should be drilled under appropriate controls that will result in penetrating the productive formation at a predetermined point that is selected after careful consideration of limitations imposed by geologic structure and drainage principles. The surface location of the well is conveniently, but not necessarily vertically, above the point of penetration of the producing formation. Topographic features and inaccessibility of a surface location vertically above the selected point of penetration may make some other surface location preferable or necessary. In this event, the well must be directionally controlled during the progress of drilling from the surface location to the point selected for penetration of the producing formation. This will involve use of devices to achieve deflection of the well in the desired direction and at a suitable angle from the vertical to reach the point selected for penetration of the reservoir rock. Well-surveying instruments must be depended upon for assurance that the course of the well is toward and finally attains the desired objective. Indeed, it was the perfection of well-surveying methods that focused attention on deviations in the course of drilled wells and made possible the development of directional drilling techniques.

In a broad view a vertical well is a directionally drilled well if the objective has been to penetrate the producing formation at a point vertically below the starting point, but common usage applies the term "directional drilling" primarily to the art of deflecting wells to reach points situated some distance away, horizontally, from the starting point. In some instances, wells have been bottomed at points distant 3,600 ft. horizontally from the starting point in a drilled depth of 5,800 ft. Deflections in excess of 45 deg. from the vertical have been attained. The art of directional drilling has so far progressed that a well may be drilled into a given stratigraphic horizon within a few feet of the point selected and the entire course of the well may be kept within a predetermined hypothetical cylinder of intervening formation not more than 25 ft. in diameter. Vertical holes may be so accurately controlled that they do not, at any part of their course, encroach beyond vertical planes projected through the four corners of the derrick.

Wells may be classified as straight, curved or crooked. A straight

hole does not deviate in either direction or slope, and may be either vertical or inclined. A curved well is maintained in a single directional plane usually though not necessarily a vertical plane, but varies in slope at different depths. A crooked hole is not confined to a single directional plane and may also vary in slope. Directional drilling strives to drill either straight or curved wells but, owing to lack of proper control, wells drilled in routine fashion often become crooked. In this event, after a well survey has been made, suitable measures may be taken to straighten the hole or start it toward its selected objective.

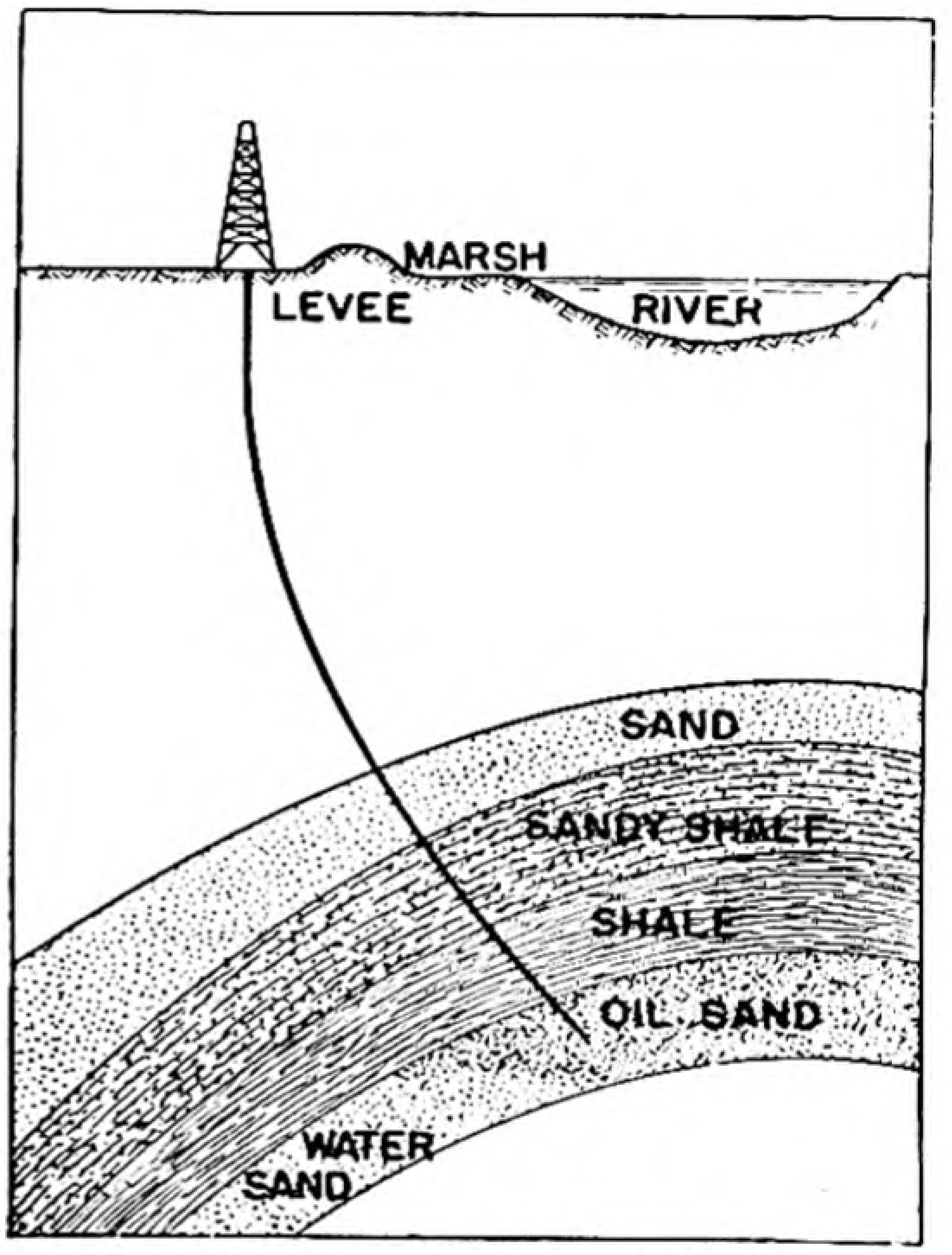
Purposes for Which Wells May Be Directionally Drilled.—Only exceptional circumstances will require that a well be drilled other than vertically. The vertical well reaches the objective with a minimum drilling footage. It is easier and cheaper to drill, operate and maintain than a deflected well. Property laws require that boundary wells shall not drift across property lines; hence it is important that such wells be directionally controlled so that they do not trespass on adjoining tracts. Yet, there are instances where wells have been deliberately deflected across property lines by directional drilling methods with the purpose of securing more prolific production than would be possible if a vertical well were drilled. In some cases, wells have been deflected into up dip prolific reservoir rocks from barren areas outside the productive limits of a "pool," and have occasioned lawsuits to recover damages for the value of oil and gas thus illegally drained.

Although use of the directional drilling art for such illegal purposes cannot be condoned, there are many circumstances that permit of its use in entirely legal and proper ways. For example, the owner of an "edge" property, partly productive and partly barren, may find that a costly well has penetrated the productive horizon outside of the productive limits of the pool. He may in this event, plug back the well some hundreds of feet and redrill by directional methods to deflect the hole up-dip into the productive portion of his own property, thus avoiding a large part of the loss that would result from the drilling of a non-productive well.

There are many instances where the surface area vertically above part of an oil field is inaccessible for drilling purposes, yet wells situated laterally some distance away may be deflected to intersect the oil-bearing formations below the inaccessible points. For example, in the Huntington Beach field in southern California, a part of the productive area of the field is situated half a mile or more offshore, under the Pacific Ocean. Wells situated onshore above high-tide level have been successfully deflected to tap the submerged area at uniformly spaced up-dip locations. A somewhat similar situation exists in the Wilmington field in the same region. Still other situations might be noted wherein productive areas

under wide rivers are reached with wells drilled from locations on the river banks (see Fig. 139). A deflected well, owing to its angular path through the oil-producing formation, may log a much greater thickness of productive formation than if drilled vertically.

It is sometimes difficult to drill a vertical well through a steeply inclined fault plane to reach an underlying oil sand. Instead, a well situated on the footwall side of the fault plane may be deflected to penetrate the oil-bearing strata. Or perhaps the well will be drilled on the "hanging-wall" side of the fault plane and, at an appropriate depth, deflected to penetrate the fault plane at approximately right angles (see Fig. 140). Oil accumulations about salt domes are often found in strata beneath an overhanging hard capping and difficultly drilled salt core (see Fig. 141). A well drilled at one side of the dome, outside of the area of hard capping and salt core, may be deflected toward the core to reach into oil-bearing strata under the overhanging capping.



(*Courtesy of Eastman Oil Well Survey Corp.*)

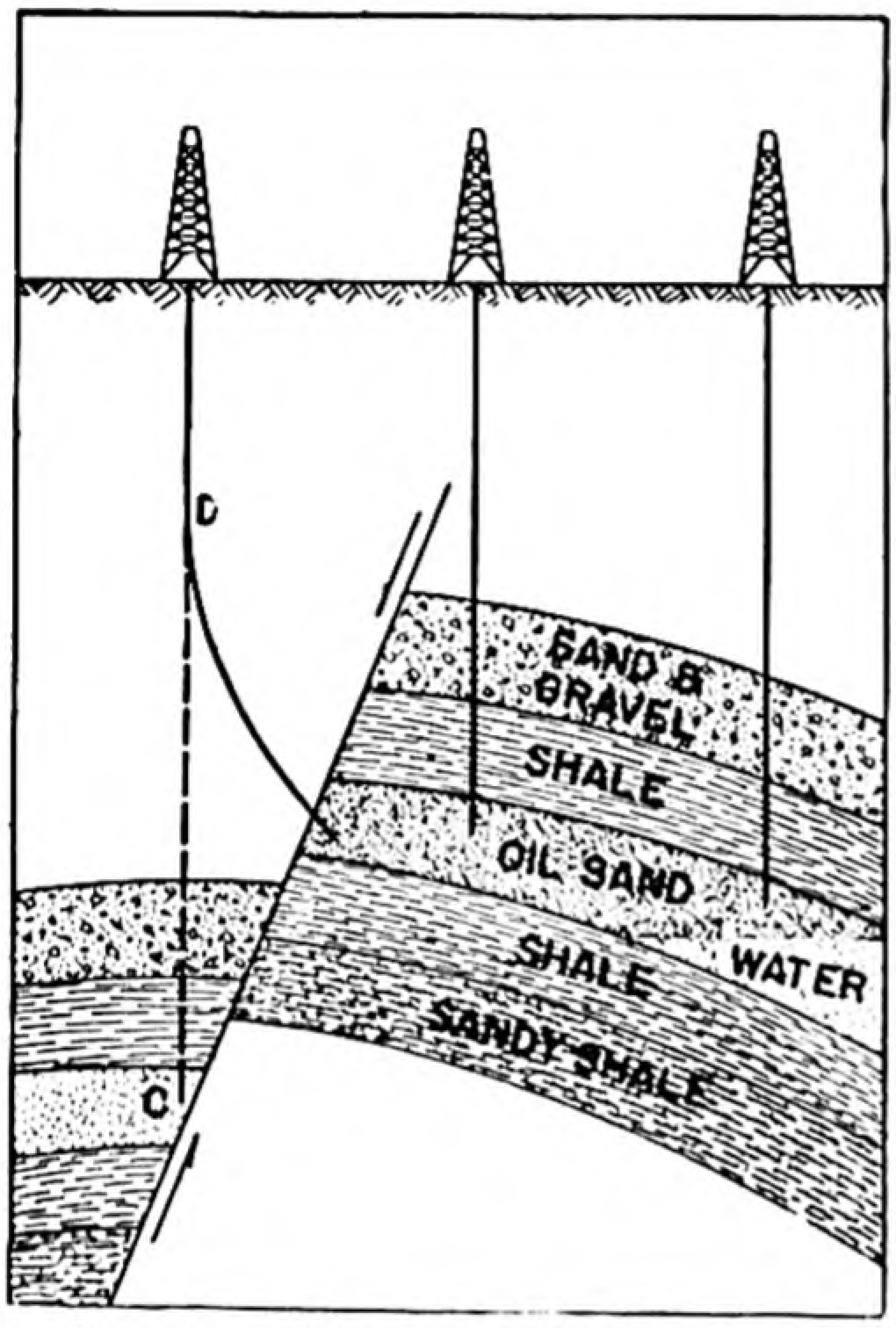
FIG. 139.—Directionally drilled well deflected to penetrate an oil reservoir beneath a river.

Directional drilling may be used profitably in exploration work in a new field. For example, a well may be drilled vertically to intersect the producing formation and then, after a production test has been made, plugged back a few hundred feet and deflected down-dip to penetrate the oil-bearing formation at a lower elevation. After a production test at this location, the hole may be again plugged back and redrilled, deflecting to penetrate the producing formation at a third point, up-dip from the first. Arrangements may be made to complete the well for production from this third area of penetration. With information thus obtained, the structural features of the locality and variations in productive capacity of the strata in different areas may be reliably determined. Dip of the formations at shallower depths, before penetrating the oil-producing strata, may be determined in similar fashion by noting the depths of penetration of a characteristic "marker" bed in two or more deflections of a single well.

Another interesting application of directional drilling was found in a situation where a crater had formed about a high-pressure burning well, so that it could not be extinguished by surface methods. A well

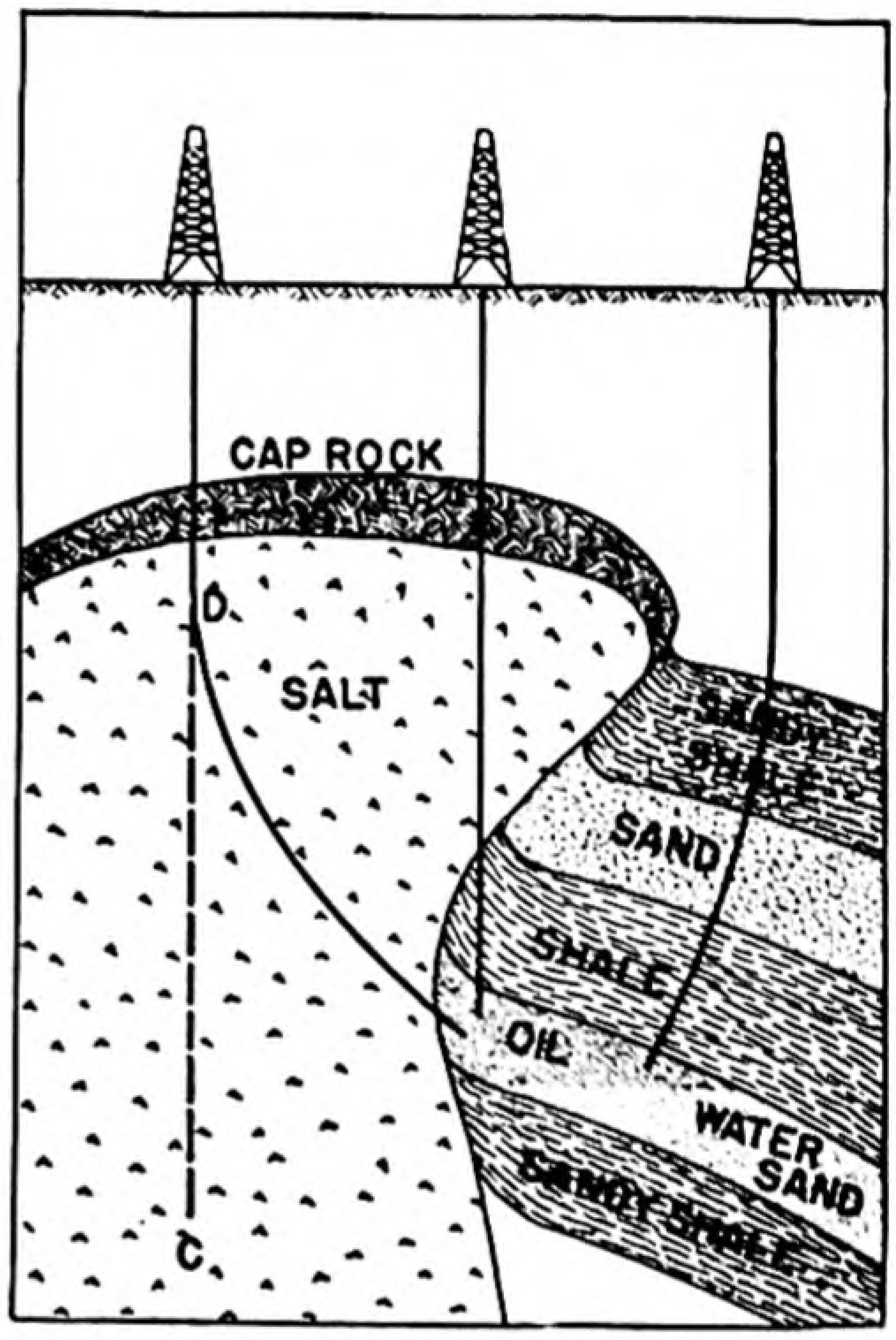
located a safe distance away from the fire well was deflected so that it penetrated the producing horizon at a point near the fire well, draining the gas from the tributary sands to such a degree that the fire could be brought under control; or, if necessary, water could be forced into the formation about the producing well (see Fig. 264).

Wells that have produced for a time, until the reservoir rock about them has been drained to the point where operations are no longer profitable, may be plugged back and redrilled, deflecting them to intersect



(*Courtesy of Eastman Oil Well Survey Corp.*)

FIG. 140.—Directionally drilled well deflected to penetrate an oil reservoir accumulated on the footwall side of a fault plane.



(*Courtesy of Eastman Oil Well Survey Corp.*)

FIG. 141.—Directionally drilled wells deflected to penetrate an oil reservoir beneath the overhanging cap rock of a salt dome.

the reservoir rock in less thoroughly drained areas. Thus, wells drilled in limestone reservoirs of low permeability under proration restrictions requiring wide spacing have been profitably redrilled. Edge wells that have been invaded by edge water may be plugged back and recompleted at higher elevations by deflection methods.

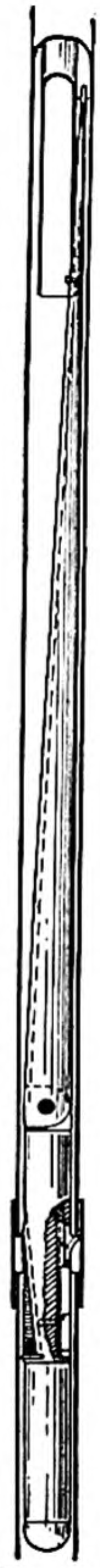
Economy in drilling operations may sometimes be realized by drilling several deflected holes from one surface location. Thus, a single rig foundation may serve for several wells. In the Elwood field of California, for example, wells are drilled from piers extending half a mile or more out from shore into the Pacific Ocean. Pier construction and rig foundations cost as much as $50,000 per location. Drilling three wells, one vertical and two deflected—one to either side of the pier—materially reduces the cost of rig foundations on a per-well basis. An interesting

development in the Huntington Beach field of California is noted, wherein deflected wells producing from an offshore portion of the field beneath the floor of the Pacific Ocean are drilled from littoral locations. At the surface, wells are spaced along a straight line paralleling the shore, only 27 ft. apart, and a single steel derrick, mounted on wheels operating on steel rails, serves each well of a group of five as circumstances may require. Bottomed in the reservoir rock from 700 to 4,600 ft. horizontally distant from the surface locations, each well drains an area of from 5 to 10 acres.

Methods of Deflecting Wells in Directional Drilling

A variety of different methods of deflecting wells during the course of drilling are employed. Deflecting a well from its vertical course is not difficult; indeed, it is often difficult to avoid in routine drilling. In rotary drilling, excessive bit pressure or excessive pump pressure on the circulating fluid will sometimes cause deflection of the well. If the rotary table is not mounted on level supports, the well will drift in the direction of the high side. If the bit is eccentric in its construction or is broken or excessively worn on one side more than another, or if the drill collar is bent, the hole is likely to depart from the vertical.

Deflecting tools, widely used in directing the course of a well toward a selected objective, include various types of whipstocks, knuckle joints and special drilling bits and reamers. The equipment to be employed will depend upon the conditions presented, particularly whether they are to be used inside a column of casing or in open hole.[24]



(Courtesy of Kinzbach Tool Co., Inc.)

FIG. 142.—Fixed type of whipstock used primarily for milling deflected holes through casing.

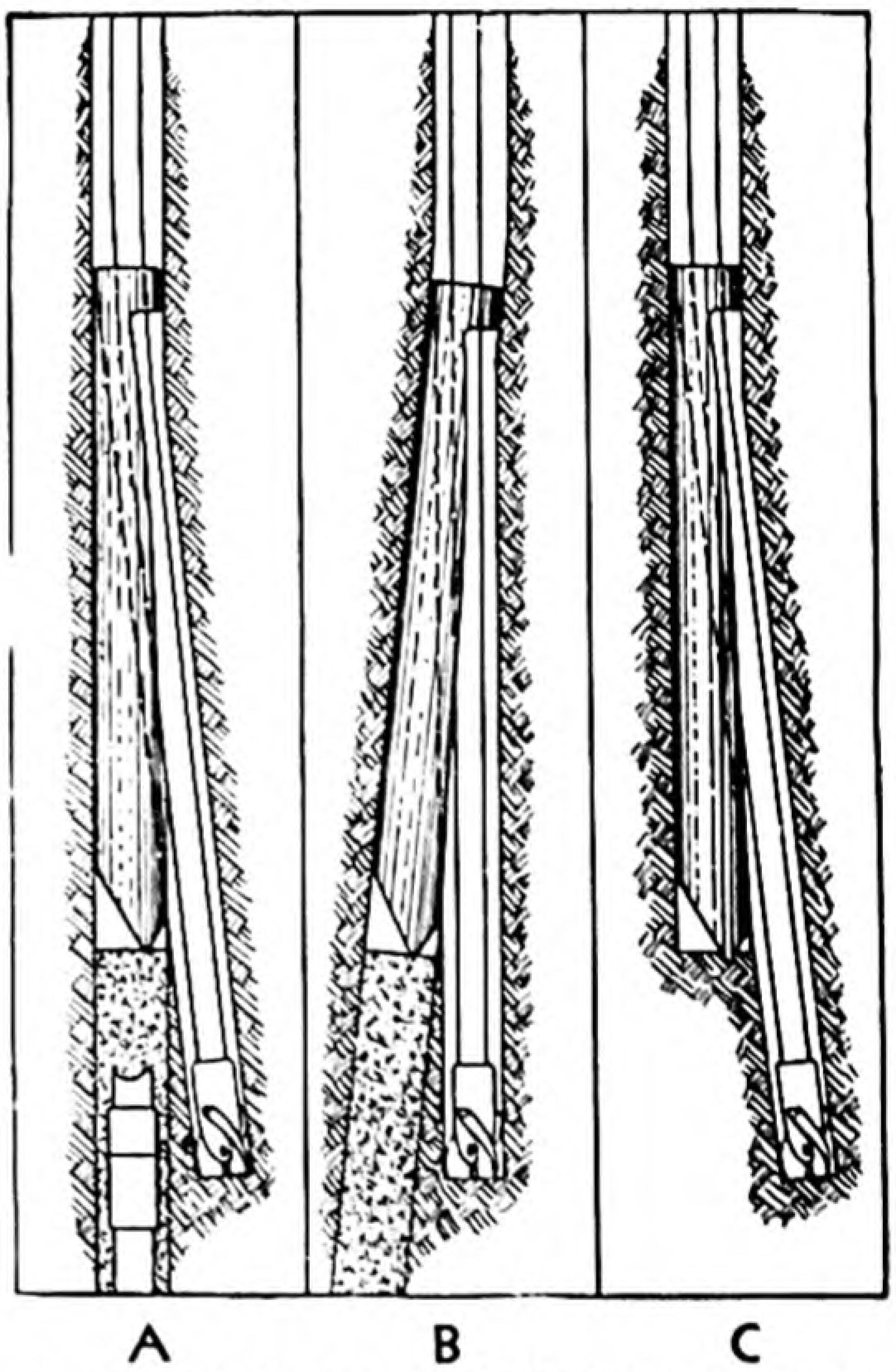
Whipstocks.—A whipstock is a long, slender, tapered steel wedge with a concave groove on its inclined face, supported in the well in such a position that the drilling tool is deflected from the previous course of the well toward the direction in which the inclined grooved surface faces. The deflection provided is usually less than 6 deg. Whipstocks are either fixed or removable. When used inside of casing, in preparation for drilling out through the casing with milling tools (see Fig. 142), the whipstock may conveniently be of a type that is locked in the casing by means of slips that maintain their position against both horizontal and vertical movement of the drilling tools. Another type is held in position by steel pins that are driven outward through the

casing when the whipstock is in position. Earlier practice involved cementing the whipstock in the desired position so that it could not turn or be displaced by the side thrust of the drilling tools.

Whipstocks used in open holes are usually of the removable type pictured in Fig. 143. This is an alloy-steel casting about 10 ft. long, 1 to 2 in. smaller in diameter than the hole in which it is to be used, with a round, concave groove on its inclined face that tapers from a collar at the upper end to the edge of the tool near the bottom. A chisel-shaped lower end, driven into the bottom of the hole by the weight of the drill column, prevents the whipstock from turning. The tool is suspended on rotary drill pipe from a bit of special design, somewhat smaller than that of the hole, which projects through and shoulders up against the collar. The drill pipe is free to pass downward through the collar but, on lifting, the bit engages the collar and the whipstock is retrieved with the drill column. No drill collar or a flexible drill collar assembly is used in order that the drill column may be as limber as possible. A shear bolt screwed into the bit through the collar holds the whipstock in fixed position with respect to the drill pipe until the tool is oriented in fixed position on bottom. When drilling is begun, the weight of the drill column shears the bolt and permits the drilling tool to advance downward along the grooved, inclined face of the whipstock. Figure 144 illustrates the manner of operation of the drilling tool as influenced by the whipstock. After the hole has been advanced 10 to 20 ft. below the whipstock, so that the hole is well

(*Courtesy of Eastman Oil Well Survey Corp.*)

FIG. 143.—Removable types of whipstocks designed primarily for use in open holes.

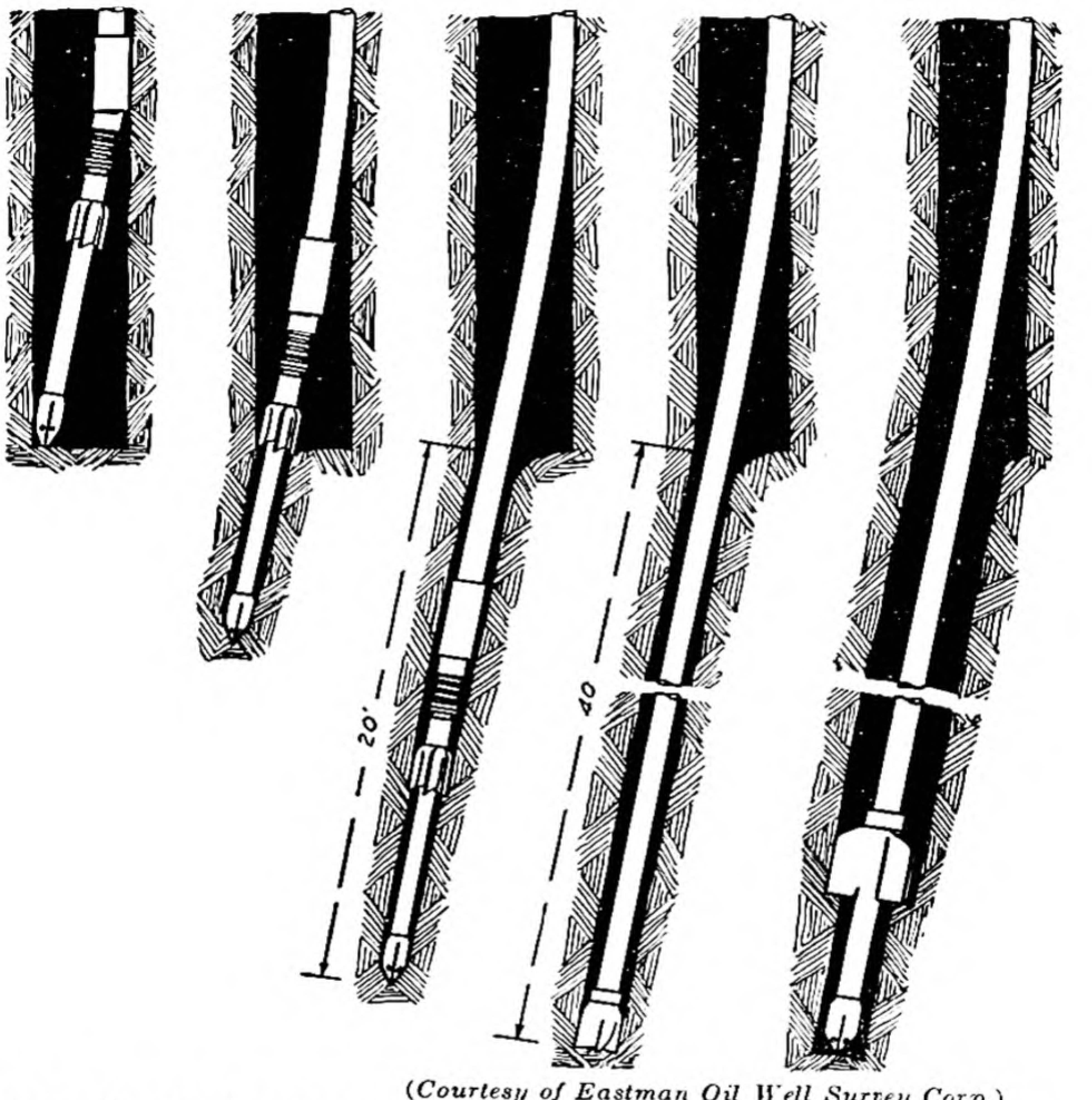


(*Courtesy of Eastman Oil Well Survey Corp.*)

FIG. 144.—Use of whipstock. *A*, sidetracking parted drill pipe; *B*, straightening crooked hole; *C*, deflecting well from vertical.

on its new course, the drill column is lifted until the bit engages the collar of the whipstock, so that the latter is removed from the well with the drill column. Usually the deflected hole must be reamed with a specially designed follow-up bit before drilling with regular equipment is resumed.

Knuckle Joints.—A knuckle joint is a special type of drill support designed to deflect the well without use of a whipstock (see Fig. 145). It is successfully employed in controlled directional drilling, sidetracking, hole-straightening and various redrilling



(*Courtesy of Eastman Oil Well Survey Corp.*)

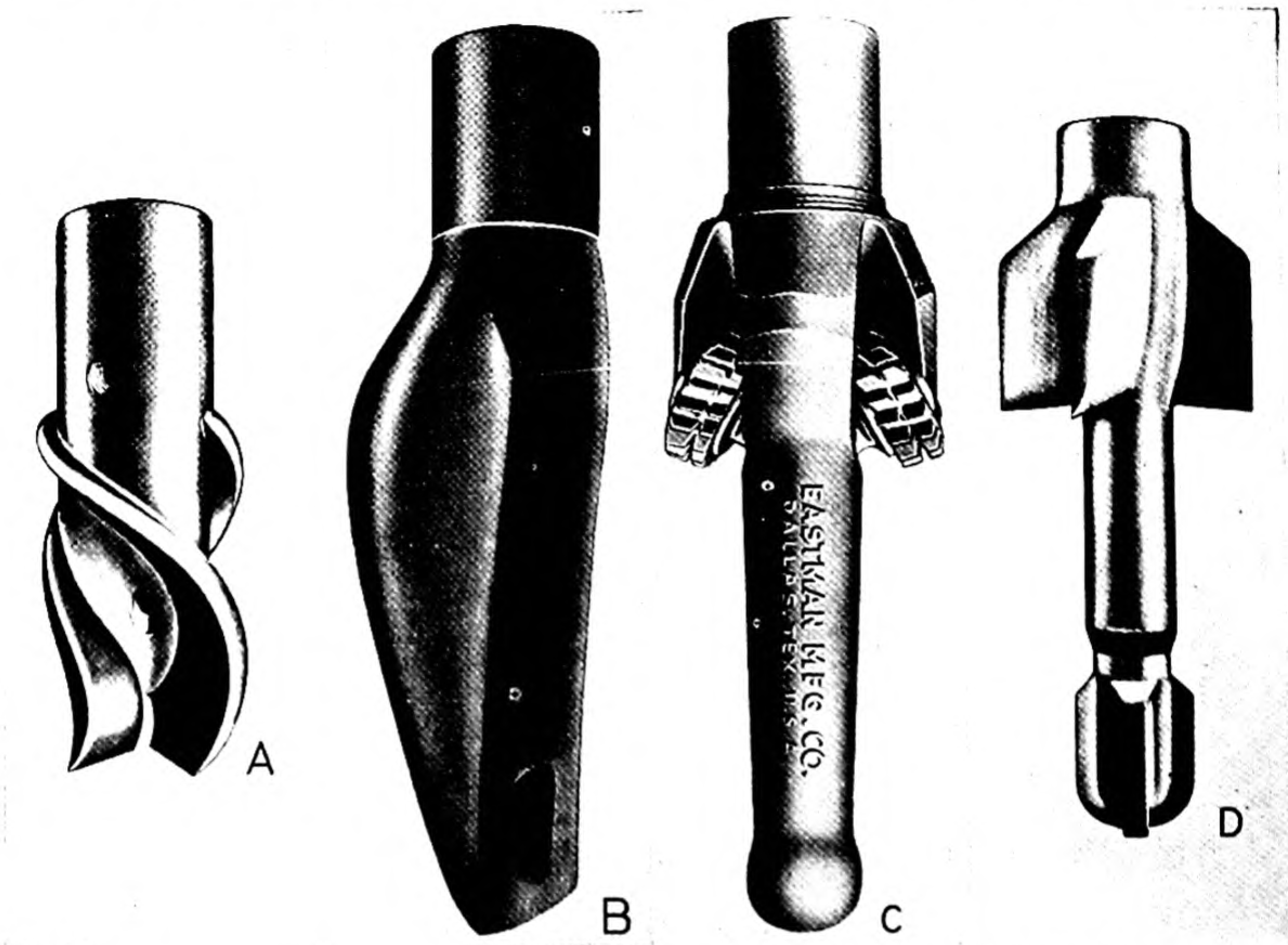
Fig. 145.—Illustrating the operation of deflecting a well with a knuckle joint.

operations. It incorporates a ball-type universal joint, connected to and rotated by the drill pipe, which allows the bit to drill at an angle to the axis of the drill column. While starting the deflected hole, the drilling assembly is maintained at a fixed angle—usually 4 to 5 deg.—by means of a spring-loaded cam, but the effective deflection angle is determined primarily by the diameter of the hole above. Under-reaming the well will permit larger deflections.

The knuckle joint, attached to the lower end of the drill column without a drill collar, is oriented on bottom so that the tool points in the direction in which it is desired to drill. Rotating slowly, with light bit pressure until the hole is deep enough for the knuckle joint to enter, the tool straightens out and the flexibility of the drill pipe takes care of the curvature of but a few degrees necessary to continue drilling in the new direction. After about 20 ft., the tool is withdrawn and a survey is made to assure that the deflected hole has taken the desired course; the hole is then reamed to full size with a pilot-reamer bit before drilling with regular equipment is resumed. The

sketches of Fig. 145 illustrate several stages in the deflection of a well with the aid of a knuckle joint.

Special Types of Drilling Bits Used in Directional Drilling.—A variety of special types of drilling bits have been devised to facilitate directional drilling operations (see Fig. 146). Some of these incorporate special features for reaming and for guiding the tool into the deflected hole. Some are equipped with retractable features (like the retractable core drill described on page 360) to permit passage of a surveying



(*Courtesy of Eastman Oil Well Survey Corp.*)

FIG. 146.—Types of drilling bits used in directional drilling. *A*, spiral-type whipstock bit; *B*, spudding bit; *C*, rock-type reamer; *D*, pilot-reaming bit.

instrument, so that a "single-shot" survey may be made in the open deflected hole without withdrawing the drill column from the well. For use with the magnetic orientation method, bits are equipped with a pair of fixed magnets. A multiblade type of drag bit is preferred for soft formations, and a cone or roller bit for hard formations. In sticky formations, self-cleaning types of bits are used. A spudding bit may be advantageously used in very soft formations, aided by the jetting action of the circulating fluid.

Technic of Directional Drilling.—Directional drilling involves a special technic with which many drillers are unfamiliar. For this reason, the work is often placed under the direction of men who specialize in the art and who assume responsibility for attaining the desired objectives on a contract basis. Frequent well surveys are necessary, and some well-surveying organizations include directional-drilling supervision in their service to the industry.

The work must be carefully planned, the limiting conditions studied, and the depth at which deflection is to be started, the deflection angle and course of the hole to reach the desired objective must be accurately calculated. It is inadvisable to make any abrupt changes in the course of the well; otherwise mechanical difficulties may develop in drilling. Initial deflections are usually 2 or 3 deg., seldom more than 5 deg. Where greater deflections are required, a curved hole is drilled with a gradual change in the deflection angle as the hole is deepened—preferably not more than 3 deg. per 100 ft. of hole. Once a deflected course has been started, further change in slope is accomplished by close regulation of bit pressure, rotational speed, pump pressure and drill-pipe torque. Increasing the bit pressure will further increase the degree of deflection. Lowering the bit pressure will reduce it. A certain critical bit pressure will maintain the drift angle already established. With drift angles above 10 deg. it is easier to maintain the established course of the hole than at lesser angles; conversely, it is more difficult to deflect a hole that has already attained a high drift angle. Drilled with a blade-type drag bit operated under 6,000 to 20,000 lb. of bit pressure, the well will tend to drift to the left (looking down the slope of the hole) if the drill column is rotated at high speed and to the right if at low speed. The drift angle does not increase so rapidly with high pump pressure as with low pump pressure when the fluid provides less hydraulic effect. A stiff drill collar of considerable length assists in maintaining an established course. It is apparent that close attention to drilling control instruments—particularly the weight indicator—is essential to obtain the desired results.

Horizontal Deflections from Vertically Drilled Wells.—For many years, oil producers have sought a means for deflecting a well after it enters the producing horizon, so that it will follow the trend of the bedding planes of the oil-yielding formations. Such a well would provide a greater drainage surface within the reservoir rock than is possible for a vertically drilled well, which provides a minimum of drainage surface in flat or low-dipping strata.

Probably the most successful device for this purpose employs a turbo drill on a flexible drill pipe that is forced out of the vertical well casing through a side-wall window. The drill pipe has a special slot cut in it to give flexibility, and a rubber lining to confine the drilling fluid, the flow of which through a geared turbine drives the rotary bit. Thus, the drill pipe does not revolve as in the usual rotary equipment.*

* For a more detailed description of the turbo drill, see p. 354. The drill pipe is left in the deflected hole to serve as a liner and the rubber lining is removed to admit production through the spiral slot. Several "horizontal" holes, entirely within the reservoir rock, extending out in different directions from the bottom of a vertical well, may be drilled with this equipment.

Orientation of Deflection Tools.—Deflection tools used in directional drilling must be carefully oriented in position, so that the well will be deflected in the desired direction. Any of the methods of orienting drill pipe and tubing described in connection with well-surveying methods may be used for this purpose (see page 712). The magnetic method is accurate and rapid and there is opportunity for a photographic check of the position of the deflecting tool before drilling is begun. A sub, connected in the drill column just above the whipstock or knuckle joint, is equipped with a pair or permanent magnets, mounted 180 deg. apart, one a north magnet and the other a south. A seat is formed in the hollow sub which supports a directional single-shot surveying instrument in a position such that a special orienting compass built into it is between the magnets. The relative azimuthal position of the magnets and the deflecting tool is determined at the surface before lowering the drill column into the well. The sub is of nonmagnetic material so that the single-shot surveying compass, located a short distance above the orienting compass, simultaneously indicates the direction of magnetic north.

In use, the deflection tool and connecting sub are lowered to bottom on a column of drill pipe. The surveying instrument is lowered on a sand line inside the drill pipe and comes to rest in the required position in the nonmagnetic sub. Two photographic records are simultaneously made, one of which indicates the position of the needle between the fixed magnets and the other the position of the magnetic needle indicating true magnetic north. The angular difference between the two records provides a means of determining the direction of the deflecting tool. The drill pipe may then be turned an appropriate number of degrees until the deflection tool points in the required direction. If desired, the new position of the tool may be checked with another single-shot survey before proceeding with the deflection drilling.

If the well has previously been surveyed to bottom and is found to be more than 3 deg. off vertical, an ordinary magnetic sub may be used and an ordinary single-shot surveying instrument without the lower orientation magnet. A single-shot survey is made with the compass of the single-shot instrument between the magnets, showing the inclination and position of the deflecting tool relative to the direction of the inclination. Since the direction of inclination of the hole is known from the previous open-hole survey, the direction of the deflecting tool can readily be determined. Experience with this method of orientation has shown that deflections may be made within an accuracy of ½ deg.

PORTABLE ROTARY DRILLING EQUIPMENT

For drilling to shallow and moderate depths, rotary drilling equipment may be designed to facilitate ready portability and ease of assembly

and disassembly at drilling sites. Parts of such rigs are usually unitized so that a minimum of rigging up and tearing down is necessary in moving from one location to another. Much time is saved in such operations and a larger percentage of rig time is spent in actual drilling than is possible with conventional rotary equipment. Drilling costs are thereby materially reduced. Such equipment is often powered with internal-combustion engines so that the problems of fuel and water supply are much simplified. Portable rigs are especially useful in drilling exploratory wells for geological information in difficultly accessible locations and in routine development work in fields where the producing formations are encountered at shallow or moderate depths.

We may classify portable rotary drilling equipment under two general types: (1) truck-mounted self-propelled rigs and (2) skid-mounted rigs. In the first group, a prime mover, draw works and slush pump are mounted on one or more trucks or tractors which, after being backed up to the derrick floor or otherwise located for operation, remain in their position on the bed of the truck or tractor. Prime movers are usually gasoline, diesel, natural gas or butane engines; electric power has also been used to a limited extent. Portable masts or standard derricks may be used in conjunction with such rigs, the trend of preference being toward quickly assembled and erected sectionalized or folding masts. Skid-type portable rigs are mounted, unitary fashion, on steel skids so that the equipment may be transported on the bed of a motor truck but removed from the truck and placed on prepared supports and foundations at drilling locations.

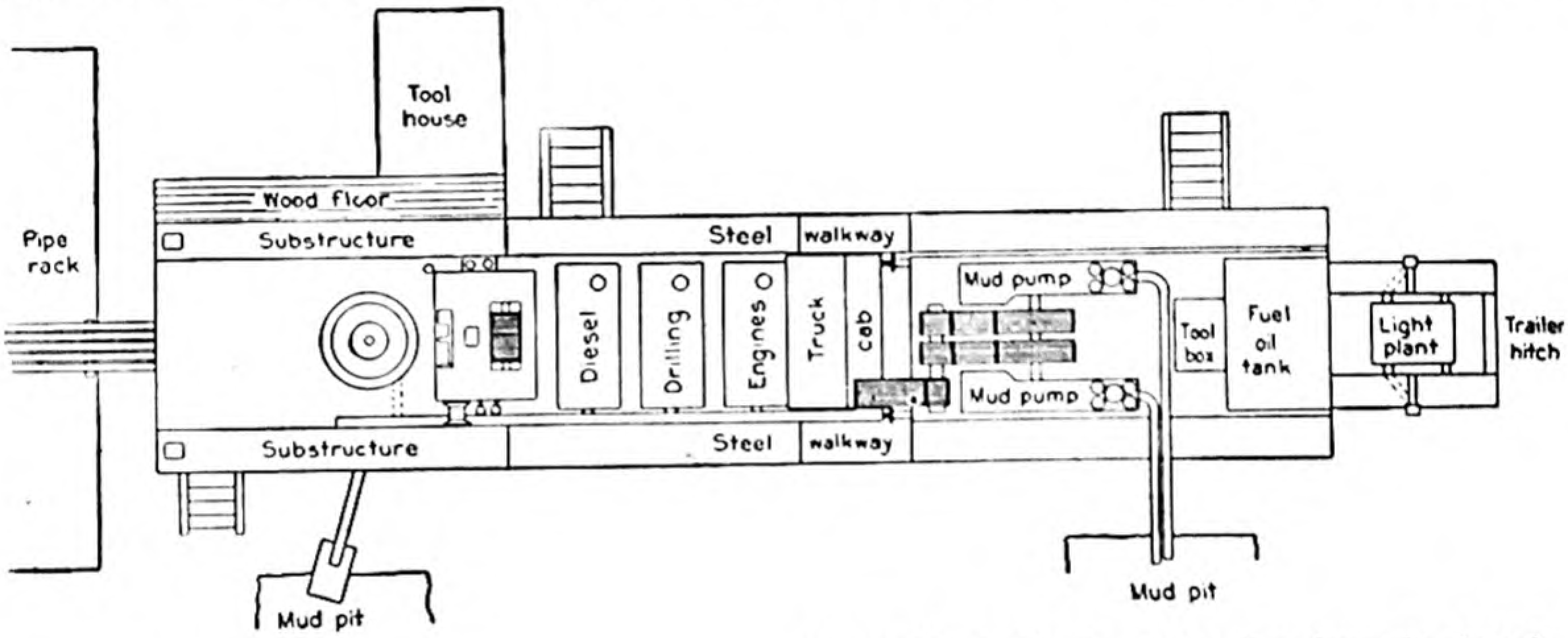
In preparing a site for drilling with a portable rig, a concrete slab may be laid down first, incorporating in it necessary foundations for drilling and production equipment, and providing I bolts for securely anchoring the portable drilling equipment. Drilling fluid may be stored in steel tanks and drill cuttings are settled in sectionalized steel flume. Wide variation is noted in design and arrangement of equipment in portable rigs sold by different manufacturers. Space permits only brief descriptions of a few of the many rigs of this type that are available. These have been selected as typical of the more popular designs.

Truck-mounted Rigs.—Truck-mounted portable rotary rigs are commonly used in drilling to depths of less than 5,000 ft.; however, development of this type of equipment has recently resulted in heavier models capable of reaching 8,000 ft. One of the lighter single-truck models and one of the heavier models carrying its own sectionalized drilling mast are described in the following sections.

A simple type of truck-mounted rig for comparatively light rotary drilling service comprises a mud pump, a draw works and an internal-combustion engine mounted integrally on a 7½- or 10-ton truck of 225-in. wheel base. The regular truck motor furnishes power for moving from one location to another and may also be called upon to assist in hoisting drill pipe and in operation of the slush pump. The

mud pump is conveniently placed transversely on the bed of the truck, immediately behind the cab, and is driven by a power take-off from the truck motor. The drilling engine, mounted parallel with and beside the pump, drives the draw works and rotary table. The draw works is supported on the rear of the truck, while the rotary table is separately mounted on skids to be placed in its usual position over the well. Suitable chain belt must be rigged to drive the table from the line shaft of the draw works. By means of specially designed transmission gearing, the engine that drives the truck can be compounded with the engine mounted on the bed of the truck for handling drill pipe and other heavy loads.

In rigging up, the truck is simply backed up to the derrick, so that the rear end of the truck frame rests on the derrick floor. The front end is blocked up so that all weight is taken off the truck springs. Such a rig, powered with two 224-hp. engines, can lift 4-in. drill pipe from depths as great as 4,000 ft. Hoisting speeds compare



(*After W. A. Sawdon in the Petroleum Engineer.*)

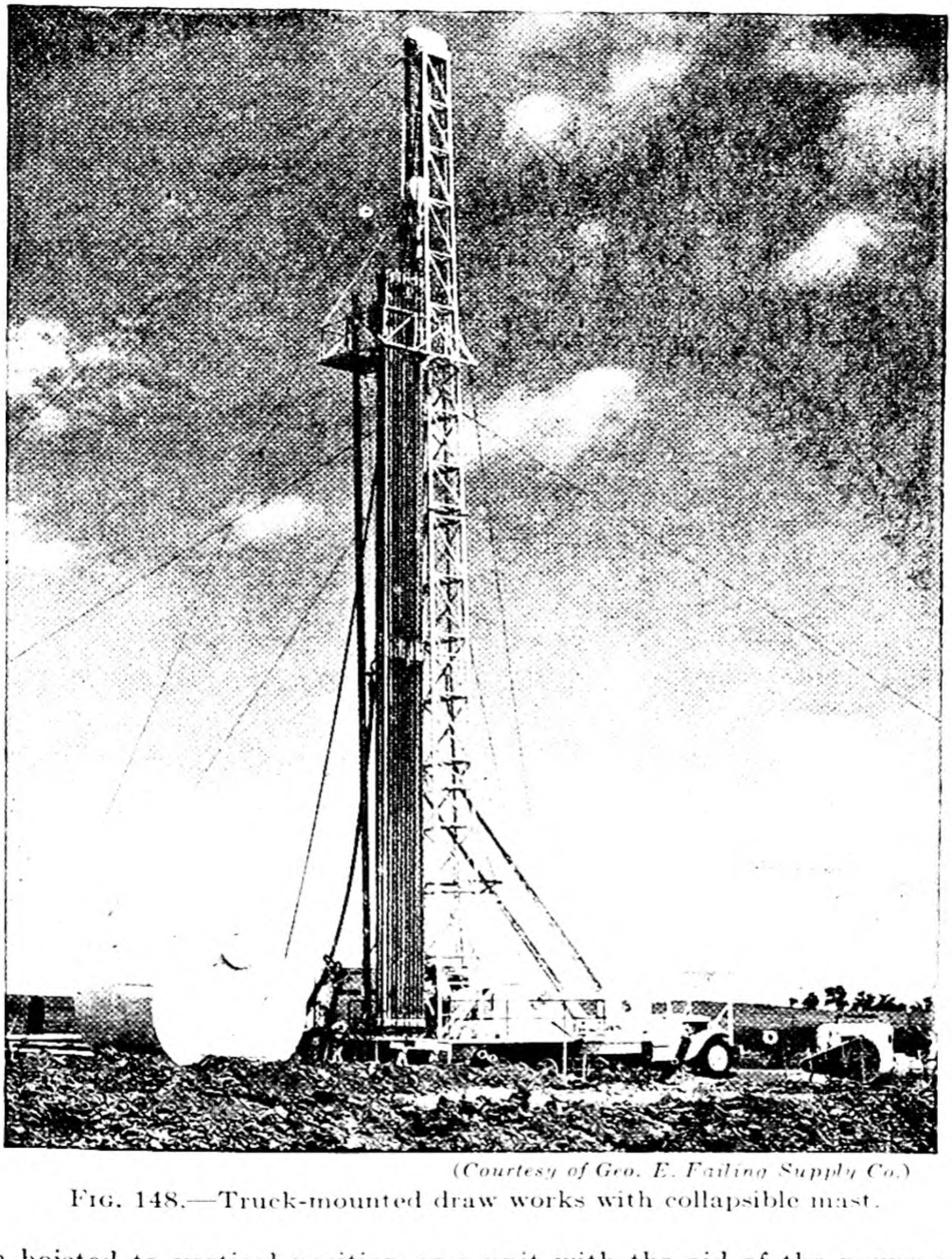
FIG. 147.—Arrangement of component parts of heavy truck-mounted portable rig for drilling to 8,000 ft.

favorably with speeds attained with heavier stationary rigs. Butane can conveniently be used as an engine fuel at a cost of as little as $15 per day. Rigging up may cost as little as $160. Under favorable conditions, all may be in readiness for drilling 24 hr. after arriving on location. Such a rig will weigh 24,000 lb. and costs about $18,400. Using one driller, one derrick man and two floormen on tour, and a mechanic available for part-time repair service, the labor cost of rig operation in some localities is about $92 per day. Truck-mounted rigs of this type are advantageous in drilling wildcat wells to depths as great as 4,000 ft. in areas where fuel and water are scarce and costly, and where transportation is difficult; also, in drilling in established fields at depths up to 3,500 ft. under conditions where mobility and shorter rigging-up time offset slightly slower drilling time.[37]

A larger and heavier type of truck-mounted rotary rig is illustrated in Fig. 147. This rig carries its own 122-ft. cantilever-type mast, constructed in three sections, and is capable of drilling with 3-in. drill pipe to depths as great as 8,000 ft. (see Fig. 33). Four trucks are required to transport the equipment. The heaviest is an all-wheel-drive truck upon which are mounted three 150-hp. Cummins diesel engines, a six-speed draw works, rotary table and transmission mechanism, and the bottom section of the mast. Motive power for moving the truck from location to location is furnished by one or more of the drilling engines. The second vehicle, in the form of a trailer designed to be drawn by a motor truck, provides a permanent base for two 7¼- by 12-in. slush pumps, an electric generator and storage batteries for lighting the rig at night, a fuel tank and the middle section of the mast. A second truck transports

a steel substructure for the rig and the upper section of the mast; a third truck carries a tool house and pipe-rack structure. Still another truck may be used for moving drill pipe or, in short moves, one of the other trucks may make one or more additional trips in moving drill pipe.[40]

The mast is constructed of tubular members, the three sections being fastened together by means of bolts and substantial steel pins while in a horizontal position,



(*Courtesy of Geo. E. Failing Supply Co.*)

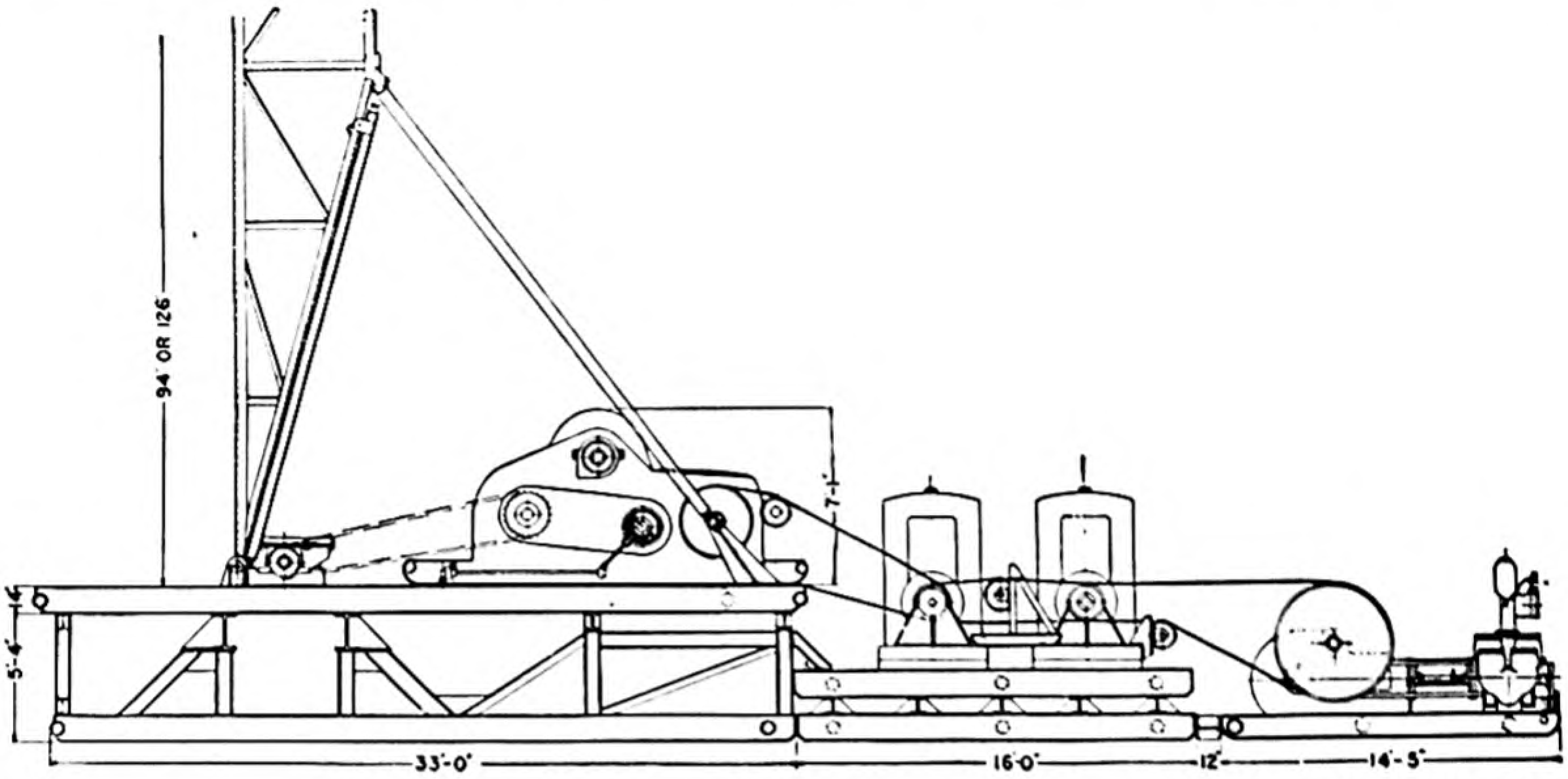
FIG. 148.—Truck-mounted draw works with collapsible mast.

and then hoisted to vertical position as a unit with the aid of the power and draw works (see Fig. 33). When in working position, the mast rests on a substantial A frame and, for security against wind loads, is guyed in four directions.

Figure 148 pictures a popular type of truck-mounted rotary draw works carrying a collapsible 60-ft. mast. The skid-mounted rotary table and power-driven slush pump are separate units carried on a second truck.

Skid-type Portable Rotary Drilling Rigs.—In this type of rig, parts are unitized

and grouped for convenience in rigging and transport but are not attached permanently to the vehicle on which they are moved. They are, however, attached permanently to steel base skids, so that they can be moved without disassembly except for connections between the unitized sections. Rig-up time is necessarily somewhat longer than with truck-mounted rigs. Ordinary service trucks or tractors are used for transport and the several units may be arranged under a conventional derrick or a portable unitized mast. A rig of this type may comprise two to seven



(*Courtesy of Lucey Corp.*)

FIG. 149.—Skid-type portable rotary drilling rig with cantilever-type portable mast.

truck loads of equipment, depending upon the size and weight of parts and the capacity of the truck.

Figure 149 pictures a rig of this type, designed for drilling to depths as great as 6,000 ft. This provides two 200-hp. diesel engines, arranged side by side, compounded to drive two pumps and a draw works. A separate rotary table is driven in the usual way from the line shaft of the draw works. The engines, pumps, draw works and rotary table each constitute a separately mounted unit. The draw works rests partly on the derrick floor, partly on an extension of the skids supporting the engines. The steel substructure may provide for support of all parts of the rig at the elevation of the derrick floor or on two or three different levels. A convenient arrangement places the draw works at the level of the elevated derrick floor, the pumps on the ground, 8 ft. lower, and the engines at an intermediate level. The several units comprising this rig weigh about 80,000 lb., and the heaviest unit—the pump—weighs about 22,500 lb.

THE COST OF ROTARY DRILLING

The cost of rotary drilling varies widely, depending upon the depth and nature of the formations penetrated, the method of drilling used, the skill of the drillers employed, the diameter of the hole and the casing requirements. Drilling costs are also influenced by fortuitous circumstances. The accidental loss or breakage of a tool in the well, collapse of the casing, a blowout of high-pressure gas resulting in loss of control, or an unsuccessful water shutoff may result in higher unit

costs. Cost data therefore are of little value for comparative purposes unless the complete drilling history of the well and a thorough description of the formations penetrated are made available. Data on drilling costs seldom give this information.

The costs of labor, lumber, steel, cement and other material, of transportation, water and power supply are also important variables. Aside from regional variation, the unsettled commodity markets and readjustments in wage scales have an important influence on drilling costs. The figures given in Tables XXVIII and XXIX on the cost of rotary drilling must be regarded as representing merely the cost of particular wells under the conditions presented in individual cases, and they should not be applied except in a very general way in estimating costs for wells drilled, perhaps, under quite dissimilar conditions.

TABLE XXVIII.—COST OF ROTARY DRILLING IN VARIOUS AMERICAN OIL FIELDS IN 1928*

Field and district	Depth, ft.	Cost of						Cost per foot of depth
		Derrick or rig rental	Casing and fittings cementing	Drilling	Labor, teaming and freight	Miscellaneous	Total	
Earlsboro pool, Seminole, Okla.	4,350	$ 5,000	$14,500	$37,950	$2,500	$ 750	$ 60,700	$13.95
Carr City pool, Seminole, Okla.	4,817	10,040	12,097	37,722	2,257	201	62,317	12.94
South Little River, Seminole, Okla.	4,198	6,881	12,693	35,193	2,047	15	56,829	13.54
Searight pool, Seminole, Okla.	4,355	7,944	17,689	41,011	2,565	829	70,038	16.08
Bowlegs pool, Seminole, Okla.	4,323	7,374	11,804	48,550	3,022	1,418	72,168	16.69
Seminole pool, Seminole, Okla.	4,115	8,348	15,926	33,804	2,494	2,232	62,804	15.26
St. Louis pool, Okla.	4,199	8,998	6,886	37,248	1,982	94	55,208	13.15
Sugarland field, Tex. (Gulf)	3,400	3,754†	17,570	6,934	1,243	3,002	32,503	9.56
Racoon Bend, Tex. (Gulf)	3,500	3,293†	16,354	9,114	1,925	5,519	36,205	10.35
Inglewood, Calif.	2,300	7,380	17,760	9,300	......	13,171	47,611	20.70
Buena Vista Hills, Calif.	3,000	7,500	22,729	10,920	......	12,945	54,094	18.03
Rincon field, Calif.	3,500	9,000	32,100	19,500	......	16,160	76,760	21.93
Huntington Beach, Calif.	4,300	7,840	33,924	20,600	......	23,773	86,137	20.03
Santa Fe Springs, Calif.	5,800	6,350	45,000	33,600	......	35,974	120,924	20.85
Kettleman Hills, Calif.	7,200	7,150	64,275	51,084	......	75,228	197,737	27.46

* Compiled from data given in "Petroleum Facts and Figures," 2d ed., Am. Petroleum Inst.
† Charge for rig rental. Drilling rig is removed on completion of well and production rig substituted.

Casing is generally the greatest single item of expense in the cost of a well, while the labor cost and the cost of the rig and derrick are the only items of comparable magnitude. Usually about one-quarter or one-third of the cost of the well is represented by the single item of casing. A derrick for a rotary rig costs from $2,600 to $3,500. Other items that are properly included among preliminary expenses are the cost of grading roads, excavating cellars and mud pits, provision of

water and fuel lines. Labor is often about 25 per cent of the total cost of drilling. Other large items under this heading are depreciation of drilling equipment, drilling bits and other expendable supplies, drilling fluid, fuel, water and boiler-plant expense. The same items also comprise an important part of well-completion expense, in addition to the cost of cementing casing, well shooting or acid treatment. Well surveys and special logging services may also represent important items of well-completion expense.

A convenient method for roughly estimating drilling costs involves the use of per-diem rates for operating expense and average rates for drilling speed, cost of derrick, foundations, casing and depreciation of drilling equipment. Thus, for conditions presented in the Los Angeles Basin and deeper San Joaquin Valley fields of California, in drilling with heavy-duty rigs to depths of 5,000 to 10,000 ft., the daily cost of operating a rotary rig, using three crews, each working 8 hr., averaged during the decade 1930–1940, approximately $500 per day, distributed about as follows:

	Cost per Day
Labor	$120
Supervision	30
Fuel and water	40
Depreciation of drilling equipment	200
Tools and repairs, including drilling bits	110
Total, per day	$500

The number of days necessary to drill a well in a given locality will depend upon local conditions, but may usually be estimated approximately. Figure 121 indicates average drilling times to various depths in two California fields, using rotary equipment. Table XXX gives the number of days required to drill the wells for which cost data are presented in Table XXIX, and a breakdown showing the time devoted to various phases of the work. It will be noted that in most cases less than half of the total time is devoted to routine drilling.

Many operators find it profitable to have their wells drilled by contractors who furnish everything necessary except the derrick and its foundations, water and fuel, casing and fixed equipment. The contract provides for drilling the well to the required depth at a specified rate per foot, so that when this practice is followed it is possible to estimate in advance the cost of the well to the producer with fair precision. It is also customary to contract cementing jobs, well-surveying and logging services, well shooting and acidizing. Rig building, road grading, pipe-line construction and oil tankage are often contracted to concerns or individuals specializing in such work.

A considerable part of the rig, drilling equipment, boilers, etc., may be

TABLE XXIX.—COST OF ROTARY DRILLING, 1934–1939*
(Using steam power in the California, New Mexico and Texas fields)

Location	Depth, ft.	Preliminary costs	Drilling costs	Completion costs	Well equipment	Total cost	Cost per ft., drilling only	Total cost per ft.
California	3,150	$2,990	$ 13,098	$ 2,729	$10,245	$ 29,062	$ 4.16	$ 9.23
California	3,725	2,990	18,980	2,354	10,587	34,911	5,10	9.37
California	3,779	2,990	27,340	2,363	10,587	43,280	7.23	11.45
California	3,845	3,070	19,610	4,106	11,454	38,240	5.10	9.95
California	4,090	2,990	22,737	4,245	10,587	40,559	5.56	9.92
California	7,752	3,570	38,694	4,197	15,435	61,896	4.99	7.98
California	7,755	5,581	90,610	12,436	47,160	155,787	11.68	20.09
California	8,270	9,100	107,447	13,206	50,850	180,603	12.99	21.84
California	8,675	7,200	77,020	15,320	52,615	152,155	8.88	17.54
New Mexico	3,763	1,296	15,562	3,125	7,440	27,423	4.14	7.29
New Mexico	3,784	1,059	14,687	5,320	7,747	28,813	3.88	7.61
New Mexico	4,765	1,045	24,853	9,007	8,660	43,565	5.22	9.14
Texas Panhandle	2,996	816	9,701	3,387	7,971	21,875	3.24	7.30
East Texas	4,180	630	8,207	2,262	6,316	17,415	1.96	4.17
Texas Gulf Coast	6,051	985	9,997	2,025	8,227	21,834	1.65	3.61
Texas Gulf Coast	8,090	1,783	23,414	3,893	16,443	45,533	2.89	5.63

* After J. E. Brantly, in "Elements of the Petroleum Industry," Am. Inst. Mining Met. Eng.

TABLE XXX.—ANALYSIS OF DRILLING TIME IN ROTARY DRILLING, 1934–1939*
(Using steam power in the California, New Mexico and Texas fields)

Location	Depth, ft.	Rigging up, days	Tearing down, days	Drilling, days	Repairing rig, days	Casing and cementing, days	Completing, days	Coring, days	Miscellaneous, days	Total, days
California	3,150	1.0	1.3	9.2	.5	8.0	2.4	1.0	.6	24.0
California	3,725	1.0	.6	15.9	.8	10.6	.8	3.3	1.0	34.0
California	3,779	.9	1.3	28.2	.8	10.5	1.3	2.1	1.9	47.0
California	3,845	1.6	.5	12.8	.6	6.9	11.0	1.3	2.3	37.0
California	4,090	1.2	1.5	21.9	.6	9.3	8.5	1.9	1.1	46.0
California	7,752	4.7	1.0	21.5	4.2	7.8	5.0	1.1	5.7	51.0
California	7,755	11.8	.7	93.2	5.6	15.0	7.7	.3	8.0	142.3
California	8,270	11.2	1.4	130.0	12.0	13.1	6.9	4.4	1.0	180.0
California	8,675	11.8	1.9	90.0	6.6	15.7	9.7	7.8	2.1	145.6
New Mexico	3,763	1.0	.3	19.2	1.1	6.6	5.3	...	1.8	35.3
New Mexico	3,784	3.7	1.0	14.1	.3	7.0	3.0	5.6	.6	35.3
New Mexico	4,765	3.7	1.0	25.2	5.0	7.5	16.4	...	1.2	60.0
Texas Panhandle	2,996	2.0	1.0	19.7	1.0	4.0	7.8	...	1.5	37.0
East Texas	4,180	.9	.7	6.9	.3	1.3	.3	.1	.5	11.0
Texas Gulf Coast	6,051	.4	1.0	5.8	.2	4.8	.3	...	.5	13.0
Texas Gulf Coast	8,090	1.9	.5	13.0	.8	7.6	.7	1.2	2.3	28.0

* After J. E. Brantly, in "Elements of the Petroleum Industry," Am. Inst. Mining Met. Eng.

salvaged when the well is completed and removed to another well location. On completion of a producing well, the drilling derrick is often dismantled and replaced by a smaller, lighter and less expensive production derrick. A smaller power plant than is necessary in drilling will more efficiently serve the operating requirements. Estimates of first cost of a well may often be materially reduced if salvage value is taken into consideration, as is proper if the material and equipment removed may be used in drilling other wells or have definite sales value. If the well is nonproductive and the casings can be pulled and the drilling rig and derrick removed, as much as 30 per cent of the first cost of drilling the well may be saved.

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CHAPTER XI

CASING, CASING DESIGN AND CASING METHODS; CASING APPLIANCES

Functions of Well Casing.—Casing used in oil and gas wells is designed to serve several purposes. It supports the walls of the well and checks caving tendencies of unconsolidated formations. Although some sedimentary rocks, particularly the harder sandstones and limestones, may stand without support for long periods of time, most of the soft, poorly consolidated sands, shales and clays cave readily and, in doing so, endanger the drilling tools and well equipment, develop cavities about the wells and restrict progress in excavation. Casing may be used to exclude fluids in other intervals than that from which it is desired to produce; also, it prevents escape of formation fluids through the well from one stratum to another. Water must be prevented from entering the oil- and gas-yielding strata from overlying or underlying formations. Gas and oil must be confined within the well casing so that they may not escape into overlying formations. At the surface the casing affords a means of attaching a control valve by means of which flow of gas and oil may be regulated and pressure within the well controlled. In an uncased hole, gas and oil may escape through the well into lower pressure permeable formations and be dissipated through them so that complete recovery can never be effected. To avoid these difficulties, every well drilled for oil or gas is cased with at least one column of pipe; in most cases one or more telescoping "strings" will be provided to make proper provision for water exclusion and to adapt the well lining to the necessary changes in diameter of the bore as depth increases. The cost of casing is usually the greatest single item of expense in the cost of an oil or gas well, and the selection of pipe weights and sizes, the planning and design of casing installations and the manipulation of casing during insertion into the well are among the most important problems encountered in well drilling.

Requirements of Well Casing.—In order that it may effectively serve the purposes outlined above, well casing must be of strength adequate to withstand the stresses to which it is subjected in the well. The type of joint used must not only assure adequate strength but must be of such design that it may be readily coupled or uncoupled, as desired. Cylindrical in form, the casing should present as smooth a surface as

possible, both on the outside and inside: on the outside to reduce friction between the pipe and the walls of the well, and on the inside to prevent the drilling tools and other casings from catching as they are lowered through. The casing must be watertight, particularly if it is to be used in sealing off water, and it should, if possible, be made of material that resists corrosion or be protected against corrosion, particularly when in contact with saline ground waters. The material of which the casing is made must be hard and tough and rigid enough to resist abrasion and distortion by contact with the rock walls of the well or the drilling tools. The walls of the casing must be as thin as is consistent with the necessary strength in order to avoid undue loss in effective working area within the well. Inasmuch as considerable amounts of casing are necessary in oil-field development, it must be available at a price that will not be prohibitive.

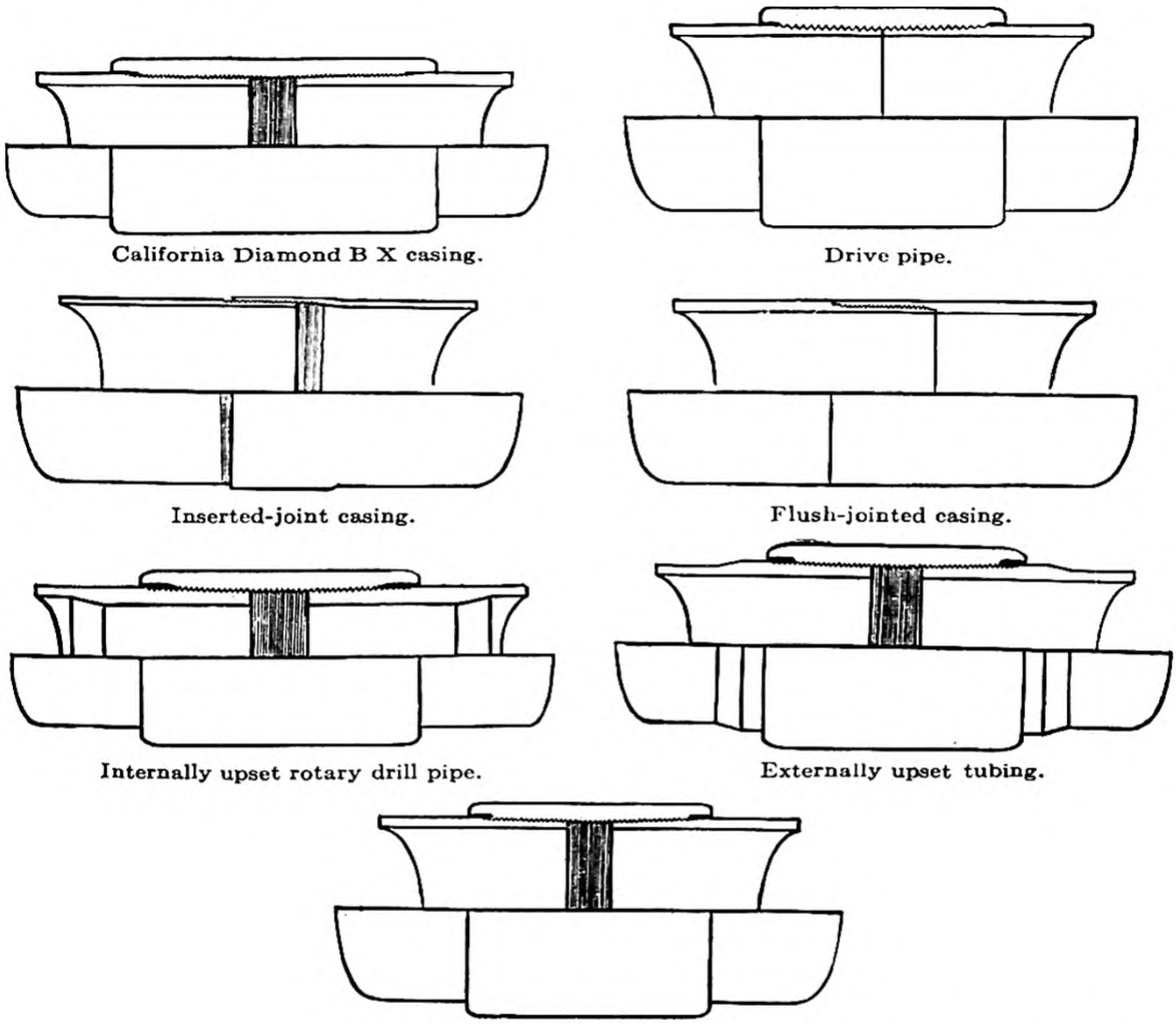
TYPES OF WELL CASING

Casings of a variety of different types are used in oil- and gas-well service. They may be classified according to (1) the type of joint used, (2) the material used in manufacture, and (3) the method of manufacture. From the standpoint of character of joint used, there are several types of threaded collared-joint casing, threaded flush-joint and inserted-joint casing; slip joints; riveted joints and welded joints. Of the materials used, various grades of ordinary carbon steel are most common, but special alloy steels and wrought iron are also used, and some varieties of surface casing are made of galvanized sheet steel. Casings may be manufactured by butt-welding or lap-welding or electrically welding the edges of steel or iron plates rolled into cylindrical form. Seamless casing is made by longitudinally punching a solid steel billet and rolling it out on a mandrel. Either smooth-surfaced or corrugated sheet metal may be rolled into cylindrical form and riveted along a straight or spiral seam. The most commonly used varieties of casing are made of ordinary carbon steel, either lap-welded or seamless, in joints 16 to 34 ft. long, coupled end to end by threaded collared joints.

Screw-joint Casing

Threaded-joint casing may be had in many different sizes and thicknesses and with several different types of joints (see Fig. 150). The collared-joint variety is generally preferred because of its greater strength, but it has the disadvantage that the collars project on the outside of the pipe, increasing friction against the walls of the well and reducing the effective working diameter. The inserted-joint and flush-joint types of threaded-joint casing are designed to minimize these difficulties but are structurally weak. Upset-end casing is strengthened

by providing additional metal at the ends of the tubes where the threads are cut, but this type of casing occasions greater loss of working area than other types.



Oil-well tubing and coupling.

(Redrawn from illustrations in handbook published by National Tube Co.)

FIG. 150.—Types of joints used on oil-well casing and tubing.

Methods of Manufacturing Well Casing.—Two fundamentally different methods are used in the manufacture of threaded-joint well casing. The products are welded casing and seamless casing. The older method involves rolling a long plate of metal of proper gauge and width ("skelp") into cylindrical form and welding the edges together along a longitudinal seam. In the production of lap-welded casing, the most widely used welded casing, appropriate for all ordinary conditions in wells of shallow and medium depth, the edges of the plate are scarfed and, when rolled into cylindrical form, overlap slightly, thus providing sufficient width of contact for proper welding. Butt-welded pipe, in which the edges of the plate are square and welded without overlap, is made only in sizes smaller than 3 in. and is not suitable for oil-well service because of its inherent weakness. After welding, the tubes are passed through cross rolls which straighten and give them a smooth exterior surface. They are then allowed to cool slowly and uniformly in order to avoid interior metal strain. When

cool, the rough ends are cut off, and later threads are cut on each end. Seamless casing, an exceptionally strong variety, is used in deep wells or under conditions where high stress is imposed. Seamless pipe is made by piercing a solid round billet of steel longitudinally through its axis, then rolling the resulting thick-walled tube on successively larger mandrels until the desired diameter and wall thickness are attained. Electric welding of the edges of a steel plate rolled into cylindrical form, without the addition of extraneous metal, produces a practically seamless tube of strength equal to that of seamless pipe.

Properties of Materials Used in Manufacture of Well Casing.—Wrought iron and several varieties of steel are used in the manufacture of well casing. Manufacturers of wrought-iron pipe claim that their product is less susceptible to corrosion than steel pipe, has superior welding and thread-cutting qualities and develops greater resistance to fatigue; but where strength, ductility and durability are important, steel is preferable. By far the greater amount of casing and tubing used in oil- and gas-well service is made of steel, and in deep wells steel is essential.

Either Bessemer, open-hearth or electric steel, wrought iron or open-hearth iron may be used in the manufacture of lap-welded casing. Open-hearth steel is most widely employed. Bessemer steel is preferred by some manufacturers because it welds readily and machines easily. Steel used in the manufacture of seamless casing is customarily made by the basic open-hearth process; or it may be an electric-furnace product. Four different grades of steel and iron for manufacture of wall casings have been established by American Petroleum Institute standards. These are designated F-25, H-40, J-55 and N-80, each possessing successively higher tensile strength and yield point in the order named (see Table XXXI). The several grades differ in carbon, manganese, phosphorous and sulphur content. An upper limit of 0.04 to 0.11 per cent is set for phosphorous, varying with the method of manufacture. Sulphur content is limited to 0.60 per cent.[2]

Table XXXI.—Physical Properties of Steel Used in Manufacture of A.P.I. Standard Casings

	Casing grade			
	F-25	H-40	J-55	N-80
Yield strength in tension (minimum), lb. per sq. in.	25,000	40,000	55,000	80,000
Tensile strength (minimum), lb. per sq. in.	40,000	60,000	75,000	100,000
Elongation in 2 in. (minimum), per cent	40	27	20	18

Steels of low-carbon content (0.1 to 0.2 per cent) characteristically have low tensile strength and yield point, but high ductility. High-carbon steels (0.4 to 0.5 per cent), with tensile strengths as high as 110,000 lb. per sq. in., are comparatively hard and brittle. However, ductility may be improved by suitable heat-treatment. Still greater tensile strength would be possible by further increase in the carbon content, with special methods of heat-treatment, but only at the expense of ductility, which is also an essential quality in well casing. High strength may also be achieved through the use of special alloy steels. Small additions of manganese, chromium, molybdenum, nickel or copper to steel may produce remarkable increase in strength and in resistance to corrosion and may also improve the ductility of high-carbon steels. Alloy steels, however, are generally too expensive for use in casing manufacture,

TABLE XXXII.—A.P.I. STANDARD CASING SIZES, WEIGHTS AND TEST PRESSURES*

O.D., in.	I.D., in.	Wall thickness, in.	Weight per ft., lb.				Calculated long coupling weight, lb.	Calculated short coupling weight, lb.	Mill test pressures, lb. per sq. in.			
			Nominal: threads and coupling	Calculated								
				Plain end	Threads and short couplings	Threads and long couplings			Grade F-25	Grade H-40	Grade J-55	Grade N-80
4½	4.090	.205	9.50	9.40	9.55	.....	.....	6.05	1,400	2,200	2,800	
4½	4.000	.250	11.60	11.35	11.47	11.54	9.07	6.05	.....	.....	2,800	2,800
4½	3.920	.290	13.50	13.04	13.14	13.20	9.07	6.05	.....	.....	.....	2,800
5	4.560	.220	11.50	11.23	11.50	.....	.....	10.18	1,300	.....	2,800	
5	4.494	.253	13.00	12.83	13.07	13.12	12.56	10.18	.....	.....	2,800	
5	4.408	.296	15.00	14.87	15.08	15.13	12.56	10.18	.....	.....	2,800	2,800
5	4.276	.362	18.00	17.93	18.09	18.14	12.56	10.18	.....	.....	.....	2,800
5½	5.044	.228	13.00	12.84	13.12	.....	.....	11.44	1,200			
5½	5.012	.244	14.00	13.70	13.97	.....	.....	11.44	.....	2,100	2,800	
5½	4.950	.275	15.50	15.35	15.59	15.64	14.03	11.44	.....	.....	2,800	
5½	4.892	.304	17.00	16.87	17.09	17.14	14.03	11.44	.....	.....	2,800	2,800
5½	4.778	.361	20.00	19.81	19.99	20.03	14.03	11.44	.....	.....	.....	2,800
5½	4.670	.415	23.00	22.54	22.67	22.70	14.03	11.44	.....	.....	.....	2,800
6	5.524	.238	15.00	14.65	15.03	.....	.....	14.53	1,200			
6	5.424	.288	18.00	17.57	17.91	17.99	18.29	14.53	.....	2,300	2,800	2,800
6	5.325	.324	20.00	19.64	19.95	20.02	18.29	14.53	.....	.....	.....	2,800
6	5.240	.380	23.00	22.81	23.06	23.13	18.29	14.53	.....	.....	.....	2,800
6⅝	6.135	.245	17.00	16.69	17.29	.....	.....	19.97	1,100			
6⅝	6.049	.288	20.00	19.49	20.04	20.17	24.82	19.97	.....	2,100	2,800	
6⅝	5.921	.352	24.00	23.58	24.06	24.18	24.82	19.97	.....	.....	2,800	2,800
6⅝	5.791	.417	28.00	27.65	28.06	28.16	24.82	19.97	.....	.....	.....	2,800
6⅝	5.675	.475	32.00	31.20	31.55	31.64	24.82	19.97	.....	.....	.....	2,800
7	6.538	.231	17.00	16.70	17.20	.....	.....	18.34	1,000	1,600		
7	6.456	.272	20.00	19.54	20.01	.....	.....	18.44	.....	1,900	2,600	
7	6.366	.317	23.00	22.63	23.03	23.15	23.67	18.34	.....	.....	2,800	2,800
7	6.276	.362	26.00	25.66	26.02	26.13	23.67	18.34	.....	.....	.....	2,800
7	6.184	.408	29.00	28.72	29.03	29.12	23.67	18.34	.....	.....	.....	2,800
7	6.094	.453	32.00	31.68	31.93	32.01	23.67	18.34	.....	.....	.....	2,800
7	6.004	.498	35.00	34.58	34.79	34.86	23.67	18.34	.....	.....	.....	2,800
7	5.920	.540	38.00	37.26	37.41	37.48	23.67	18.34	.....	.....	.....	2,800
7⅝	7.125	.250	20.00	19.69	20.55	.....	.....	26.93	1,000			
7⅝	7.025	.300	24.00	23.47	24.26	.....	.....	26.93	.....	1,900		
7⅝	6.969	.328	26.40	25.56	26.32	26.51	34.23	26.93	.....	.....	2,800	2,800
7⅝	6.875	.375	29.70	29.04	29.73	29.91	34.23	26.93	.....	.....	.....	2,800
7⅝	6.765	.430	83.70	33.04	33.66	33.83	34.23	26.93	.....	.....	.....	2,800
7⅝	6.625	.500	39.00	38.05	38.58	38.73	34.23	26.93	.....	.....	.....	2,800
8⅝	8.097	.264	24.00	23.57	24.75	.....	.....	35.58	900			
8⅝	8.017	.304	28.00	27.02	28.13	.....	.....	35.58	.....	1,700		
8⅝	7.921	.352	32.00	31.10	32.14	32.48	47.48	35.58	.....	2,000	2,700	
8⅝	7.825	.400	36.00	35.14	36.11	36.42	47.48	35.58	.....	.....	2,800	2,800
8⅝	7.725	.450	40.00	39.29	40.18	40.48	47.48	35.58	.....	.....	.....	2,800
8⅝	7.625	.500	44.00	43.39	44.21	44.48	47.48	35.58	.....	.....	.....	2,800
8⅝	7.511	.557	49.00	48.00	48.73	49.98	47.48	35.58	.....	.....	.....	2,800

TABLE XXXII.—A.P.I. STANDARD CASING SIZES, WEIGHTS AND TEST PRESSURES* (*Continued*)

O.D., in.	I.D., in.	Wall thickness, in.	Weight per ft., lb.: Nominal: threads and coupling	Weight per ft., lb.: Calculated: Plain end	Weight per ft., lb.: Calculated: Threads and short couplings	Weight per ft., lb.: Calculated: Threads and long couplings	Calculated long coupling weight, lb.	Calculated short coupling weight, lb.	Mill test pressures, lb. per sq. in.: Grade F-25	Grade H-40	Grade J-55	Grade N-80
9⅝	9.063	.281	29.30	28.04	29.32	.....	.....	39.51	900			
9⅝	9.001	.312	32.30	31.03	32.25	.....	.....	39.51	.....	1,600		
9⅝	8.921	.352	36.00	34.86	36.01	36.46	55.77	39.51	.....	1,800	2,400	
9⅝	8.835	.395	40.00	38.94	40.01	40.44	55.77	39.51	.....	.....	2,700	2,800
9⅝	8.755	.435	43.50	42.70	43.70	44.11	55.77	39.51	.....	.....	.....	2,800
9⅝	8.681	.472	47.00	46.14	47.09	47.47	55.77	39.51	.....	.....	.....	2,800
9⅝	8.535	.454	53.50	52.85	53.67	54.02	55.77	39.51	.....	.....	.....	2,800
10¾	10.192	.279	32.75	31.20	32.65	.....	.....	45.53	800	1,200		
10¾	10.050	.350	40.50	38.88	40.20	40.65	62.02	45.53	.....	1,600	2,100	
10¾	9.950	.400	45.50	44.22	45.44	45.86	62.02	45.53	.....	.....	2,500	
10¾	9.850	.450	51.00	49.50	50.63	51.02	62.02	45.53	.....	.....	2,800	2,800
10¾	9.760	.495	55.50	54.21	55.25	55.62	62.02	45.53	.....	.....	.....	2,800
11¾	11.150	.300	38.00	36.69	38.22	.....	.....	49.61	750			
11¾	11.084	.333	42.00	40.60	42.08	.....	.....	49.61	.....	1,400		
11¾	11.000	.375	47.00	45.56	46.94	47.41	67.59	49.61	.....	.....	2,100	
11¾	10.880	.435	54.00	52.57	53.82	54.26	67.59	49.61	.....	.....	2,400	
11¾	10.772	.489	60.00	58.81	59.94	60.35	67.59	49.61	.....	.....	2,700	2,800
13⅜	12.715	.330	48.00	45.98	47.64	.....	.....	56.23	750	1,200		
13⅜	12.615	.380	54.50	52.74	54.28	54.81	76.63	56.23	.....	.....	1,900	
13⅜	12.515	.430	61.00	59.45	60.87	61.36	76.63	56.23	.....	.....	2,100	
13⅜	12.415	.480	68.00	66.11	67.40	67.86	76.63	56.23	.....	.....	2,400	
13⅜	12.347	.514	72.00	70.60	71.81	72.25	76.63	56.23	.....	.....	.....	2,800
16	15.375	.3125	55.00	52.36	54.70	.....	.....	78.98	600			
16	15.250	.3750	65.00	62.58	64.71	.....	.....	78.98	...	1,100		
16	15.125	.4375	75.00	72.72	74.63	.....	.....	78.98	.....	.....	1,800	
16	15.010	.4950	84.00	81.97	83.68	.....	.....	78.98	.....	.....	2,000	
20	19.166	.4170	90.00	87.22	89.66	.....	.....	98.25	650	1,000		

* Courtesy of American Petroleum Institute.

Sizes 13⅜ in. and under are round thread; sizes 16 and 20 in. are sharp thread. All sizes 8 threads per inch; included taper, 0.0625 in. per in.

except under special circumstances where the superior quality of the metal is worth the cost.

Lengths, Diameters and Weights of Casing.—American Petroleum Institute standards provide that well casing shall be manufactured in three ranges of length: range 1, 16 to 25 ft.; range 2, 25 to 34 ft.; and range 3, 34 ft. or more. Further limitations provide that 95 per cent or more of any carload of casing of range 1 shall vary not more than 6 ft. in length, with a minimum length of not less than 18 ft. Range 2 casing in carload lots shall have 95 per cent that does not vary more than

5 ft. in length, with a minimum length of not less than 28 ft. Range 3 casing must have 95 per cent varying not more than 6 ft. with a minimum of not less than 36 ft. "Jointers" (two short lengths of casing connected by a coupling) may comprise not more than 5 per cent of carload shipments, and the minimum length of the shorter piece is 5 ft.

Sizes of casing are designated by both diameter and weight, several weights being available in each standard size. For each size, the external diameter is constant, the thickness of wall and internal diameter varying with the weight. The A.P.I., in standardizing casing used in the oil industry, has adopted a series of sizes and weights in which all dimensions are prescribed (see Table XXXII). A.P.I. standard casings are always designated by their external diameter and average weight per foot, with threads and couplings spaced at 20-ft. intervals. The manufacturing process does not permit of absolute precision in weight and dimensions, and reasonable tolerances are allowed. Any individual length of pipe may not be more than 3½ per cent under or more than 6½ per cent over the standard weights. Carload lots must not be more than 1¾ per cent underweight. The outside diameter of the pipe must not vary at any point more than ¾ of 1 per cent, over or under standard sizes. Wall thickness must not be more than 12½ per cent under the prescribed value.[2]

American Petroleum Institute specifications also provide that casing shall be "reasonably straight and free from injurious defects, such as burnt material, bad welds, sand pits, ball cuts, pits, cinder spots, liquor marks, blisters, slivers and laminations. The threads cut on casing must be free from tears, shoulders, cuts, or any defects which may break the continuity of the thread."

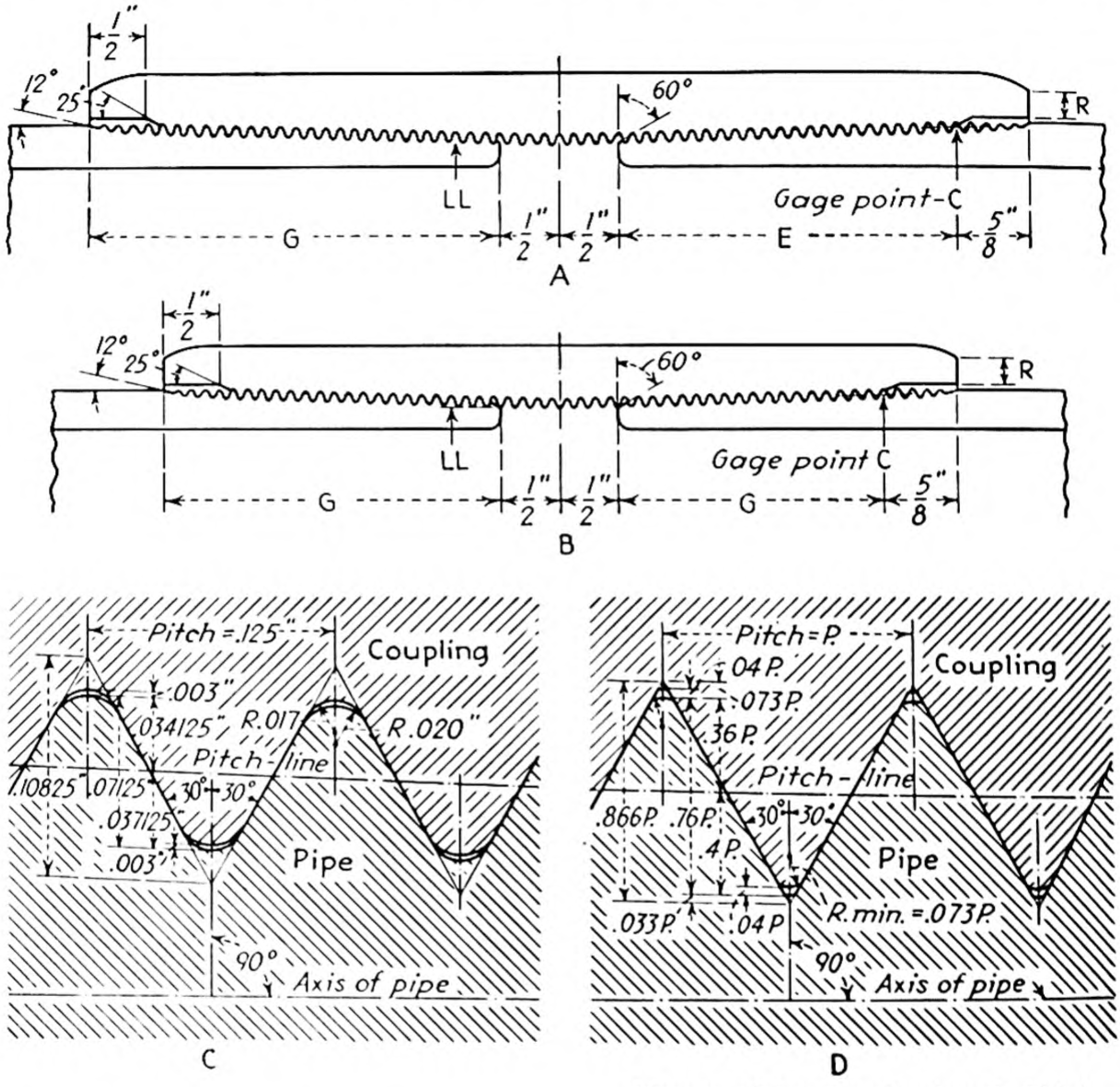
Physical tests are applied to all casing before it leaves the mill, to make certain that it conforms to specifications. In addition to the requirements suggested above, hydrostatic tests are applied to assure that the pipe will sustain a specified minimum bursting pressure. This is computed by the formula: $P = 2ft/D$, where P is the hydrostatic test pressure in pounds per square inch, t is the wall thickness in inches, D is the outside diameter in inches, and f is the allowable fiber stress. Allowable fiber stress is 15,000 lb. per sq. in. for F-25 grade casing, 24,000 for H-40, 33,000 for J-55, and 48,000 for N-80 casing. However, no test pressure is permitted to exceed 2,800 lb. per sq. in.

A drift test, made by passing through each joint of casing a cylindrical mandrel of diameter only slightly less than the inside diameter of the casing, gives assurance that the pipe is truly cylindrical in form and free from dents, internal blisters or other projections. Tension tests and flattening tests are also applied to "crops" cut from the ends of the tubes during the process of manufacture. Tests are also applied to check the alignment and dimensional accuracy of the threads. All dimensions are carefully checked by application of standardized gauges.

Casing Threads.—Threads used on well casings and couplings are usually a modified style of the Briggs standard 60-deg. V form. The A.P.I. has adopted two thread standards: one a "sharp" thread, standard for only 16- and 20-in. casing, and the other, a "round" thread standard for all smaller sizes (see Fig. 151). However, A.P.I. sharp threads have been widely used on all sizes of casing during recent years, and still may be had by special order on any size of casing from most manufacturers. The round thread develops a stronger, tighter joint and is preferred, particularly in long strings of casing used in deep wells. For some special types of flush-jointed casing, modified square and Acme threads have been used, sometimes in "step" form (see Fig. 152).

Maximum strength in a threaded joint is secured by a proper balance between the thickness of the metal walls of the pipe and the "pitch" or spacing of the threads. It is apparent that the thickness of metal resisting tensional stress, left at the base

of the threads, will be greater for shallow, closely spaced threads than for deep, widely spaced threads; but the tendency for the joint to pull apart by shearing or stripping of the threads will be greater for a shallow than for a deep thread. American Petroleum Institute standards provide that threads used on standard casings shall have a pitch of ⅛ in., or 8 threads per inch, but 10, 11½ or 14 threads per inch are preferred for some of the thinner walled, nonstandard casings where the thickness of metal



(*Courtesy of American Petroleum Institute.*)

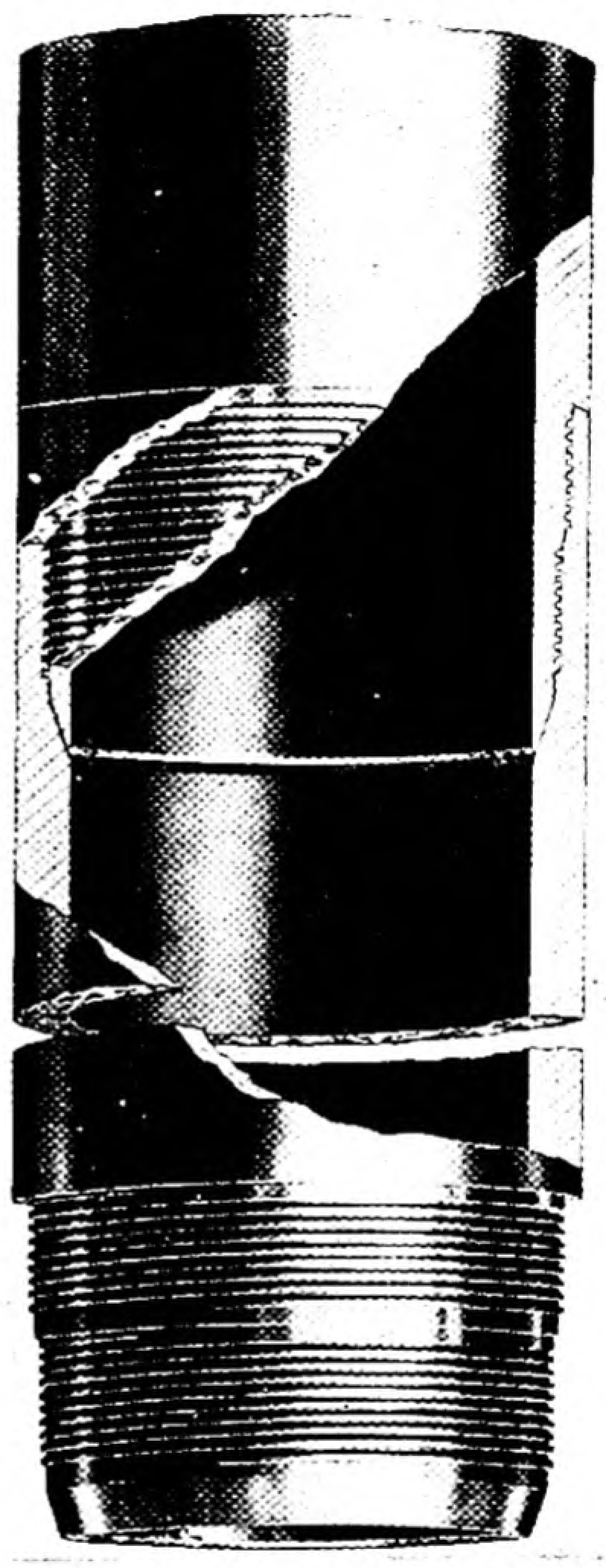
FIG. 151.—A.P.I. standard casing threads and couplings. *A*, long coupling; *B*, short coupling; *C*, rounded thread; *D*, modified Briggs' thread. Dimensions *G*, *E*, *LL*, *R* and *C* vary with size of casing.

left at the roots of the threads would be unduly reduced by cutting only 8 threads per inch.[2]

In order that the threads may tighten securely in the collars, they are cut to a slight taper with the axis of the tube. American Petroleum Institute standards specify that this taper shall be ¾ in per ft., or 1 in 16. This is suitable for an 8-thread cut, but for other pitches the taper may be ⅜ or $\frac{3}{16}$ in. per ft. The length of the thread is determined by advancing the cutting dies until the basic wall thickness at the root of the thread at the end of the pipe $= t = 0.009D + 0.040$ in., where D is the outside diameter of the pipe in inches. In no case, however, is t less than 0.90 in.

When securely made up, the ends of the tubes are 0.5 in. or more from the center of the coupling. The threaded section terminates in three imperfect threads which vanish into the contour of the cylindrical surface on which they are cut, a feature tending to strengthen an otherwise inherently weak portion of the joint where fatigue failures often occur.

Casing couplings are of special design, being generally longer and heavier than the type of coupling used on ordinary standard pipe, and having clean-cut threads of such pitch diameter as to make a secure, water-tight joint at the test pressure when properly made up with a suitable lubricant (see Fig. 151). Couplings may be either short or long, the latter being used in deep wells where security against high tensile stress and leakage under high fluid pressure is especially necessary. Short couplings are prescribed by A.P.I. standards, but purchasers may specify long couplings for casting grades J-55 and N-80. Inasmuch as all A.P.I. standard casings of a given size have the same outside diameter, one coupling may be used for all (see Table XXXIII). To aid in starting the pipe into the coupling, a recess is turned in each end. This also serves to protect the end threads which start from the bottom of the recess at either end, tapering toward the center to conform with the taper of the threads on the pipe. The recessed ends of the coupling fit snugly over the vanishing threads on the casing and thus increase, to some extent, the rigidity and security of the joint.



(Courtesy of Hydril Co.)
FIG. 152.—Hydril flush-jointed casing.

Couplings for welded casing may be made of wrought iron or steel, seamless or welded. Couplings for seamless casing and electrically welded casing are made of seamless material at least equal in physical properties to that from which the pipe is made. Long couplings made of heat-treated alloy steel (yield point 120,000 lb. and tensile strength 145,000 lb. per sq. in.) may be thinner than ordinary steel couplings, thus conserving clearance between strings of casing. Couplings must be free from blisters, pits, cinder marks and other injurious defects that would impair the efficiency of the joint and break the continuity of the thread. When couplings are made of steel, they are electroplated with lead or cadmium on the threads, heat-treated or subjected to any process that will minimize galling tendencies. Ends of couplings are faced true, at right angles to the axis, and the outside edge is beveled slightly to prevent catching on the ends of the joints of pipe through which they pass.

As shipped from the tube mills, each joint of casing is equipped with a securely made-up coupling on one end and a solid, tapped ring or thread protector long enough to cover the thread on the other end. A short, threaded nipple is also screwed into the open end of the coupling to protect the interior threads from damage and dirt accumulations. The threaded ends are doped or greased to protect against corrosion.

Types of Collared-joint Casing

A variety of casings other than A.P.I. standard casings are available, differing from each other chiefly in weight and thickness. For example, Boston and South Penn casings are well-known lighter grades that have been preferred in some regions where wells are shallow and water exclusion is not a problem of importance, and the walls of the wells require little support. Though still available from manufacturers, these grades are now less used than formerly because of adherence of most operators to the A.P.I. standards. A.P.I. casing sizes are adaptable to all ordinary conditions, but special casings of unusual size or strength may be made to order to fit particular requirements, at a cost but little higher than that of standard sizes.

Table XXXIII.—Dimensions of A.P.I. Standard Casing Couplings

O. D. of casing, in.	O. D. of coupling, in.	Length, short coupling, in.	Length, long coupling, in.
4½	5.000	5	7
5	5.563	6½	7¾
5½	6.050	6¾	8
6	6.625	7	8½
6⅝	7.390	7¼	8¾
7	7.656	7¼	9
7⅝	8.500	7½	9¼
8⅝	9.625	7¾	10
9⅝	10.625	7¾	10½
10¾	11.750	8	10½
11¾	12.750	8	10½
13⅜	14.375	8	10½
16	17.000	9	
20	21.000	9	

Sizes 13⅜ in. and under have round threads; sizes 16 and 20 in. have sharp threads.

Drive Pipe.—Drive pipe is a collared-joint type of casing, somewhat heavier than the average, which is designed particularly for use under circumstances that require heavy driving (hammering) on the upper end of the column to force it into the well. This necessity arises in tight holes where the well is somewhat smaller than its intended diameter, or where caved material from the walls accumulates about the pipe until the friction so developed prevents free movement. In order that the pipe may be driven from the surface without placing undue strain on the collars, the taper and length of the threads are so designed that the ends of the tubes butt together at the centers of the collars when the joints are made up (see Fig. 150). Although such a pipe is well adapted to driving, it is apt to be loosened in the collars in the process, so that it may part when an upward pull is applied. Development of modern methods of rotary drilling, in which the casing is left fairly free of the walls of the well, has largely removed the necessity for using drive pipe, but in former years, when cable tools were used in drilling through unconsolidated formations, it was often employed.

Upset-end Pipe.—A section of properly made pipe of uniform wall thickness is weakened by cutting threads on it. Because of metal removed in forming the threads, pipe is weakest at the base of the threads where the metal is thinnest. With the purpose of constructing threaded-joint pipe of uniform strength throughout, upset-end pipe has been developed. In this, the metal wall of the tube is locally

increased in thickness by an amount equal to or greater than the depth of the threads. In the manufacture of casing and drill pipe (see Fig. 97) the additional metal is usually placed on the inside of the pipe, but well tubing of smaller size is usually of the exterior-upset variety (see Fig. 150). American Petroleum Institute specifications provide that standard casing shall be without upset ends; however, internal-upset casing is obtainable on special order from some manufacturers. In one variety, part of the upset is on the outside, part on the inside.

Inserted-joint Casing.—When a well is shallow and a small-diameter light casing is all that is needed to sustain the walls, inserted-joint casing may be employed. This uses no couplings. In this type of casing, one end of each tube is expanded and internally threaded, so that it may receive and connect with the unexpanded and externally threaded opposite end of another tube (see Fig. 150). The threads are only slightly tapered. Modified forms have also been developed in which the outer half of the joint is expanded and the inner half is "cressed." In another variety, a light, faced ring is screwed on the externally threaded end to serve as a kind of lock nut, against which the outside or expanded half of the joint butts when the parts are securely made up. This prevents the expanded end from splitting and adds to the security of the joint to such an extent that it can be lightly driven.

Inserted-joint casings are structurally weak, and there would appear to be little justification for their use in oil- and gas-well service. Many assume that they conserve working space where clearance between strings or in an undersize hole is small, but comparisons of external diameters of inserted joints with outside diameters of couplings on collared-joint pipe of equivalent size show but little difference. However, when run in a tight hole as an oil string or liner, with female ends up, this type of pipe has an advantage over coupling joints in that it presents no projecting edges to scrape material from and "hang up" on the wall of the well.

Flush-jointed and Semiflush-jointed Casings.—Flush-jointed casing is made by turning down and cutting a thread on one end of a tube, so that it enters and joins with the reamed and internally threaded opposite end of another tube. The end of one tube thus screws into the other without the necessity for a collar and the joint has no visible edges or corners, either on the outside or inside (see Fig. 150). Such a joint is particularly useful where the diameter of a well has become so reduced that it is important to use a casing that occupies the smallest possible space. Because of its smooth exterior surface, it is useful also in casing off loose sands which tend to cave and pack around the couplings of ordinary pipe; and in pressure drilling or snubbing pipe into high-pressure wells where projecting collars may cause difficulty in passing through surface casing heads. However, this joint is inherently weak as a result of cutting away half of the metal on each tube at the joint. The threads must be shallow and they tend to pull apart under tensional stress. Flush-jointed casing is screwed together until the ends of the tubes butt together at the center of the joint. In this condition, it is watertight, though not recommended for water exclusion under high pressure. It can also be lightly driven, but any deflection from the vertical will generally result in fracture at the base of the threads.

Special forms of flush-jointed casing largely overcome the objections to the common type described above. One of these uses a two-step square thread made up of two sections of different pitch diameters. One end of each tube has a "pin" thread and the other a "box" thread, so that the two join without any coupling to form a joint of the same interior and exterior diameter as the casing itself. Threads are cut on cylindrical rather than tapered surfaces. A conical section on the end of the pin fits snugly into a corresponding recess in the bottom of the box to restrict joint leakage. By slight external upsetting of the tubes at the ends, this joint can be made almost as strong as the pipe itself (see Figs. 130 and 152).

A special type of semiflush coupling casing is also available. In this, the pipe is internally upset at the ends and threads are cut on a depressed exterior surface. A thin coupling of high-grade steel of the same outer diameter as the pipe connects the ends of the tubes. This pipe is thus flush on its exterior surface, except for a slight depression at either end of the collar, but has a slightly smaller inside diameter at the joints than elsewhere.

Flush-jointed casings of the stronger types have been used as drill pipe in drilling by the rotary method through high-pressure or "heaving" formations. Collapsible bits are used so that the pipe does not have to be withdrawn and, when the difficult interval has been penetrated, the pipe is left in the hole to serve as a casing. As much as 2,000 ft. of heaving shale have been successfully penetrated by this method.

Welded-joint Casing

Butt Welding.—It is feasible to butt-weld joints of plain-end casing, end to end, as they are lowered into a well and, if the welding is properly done, the joints are as strong in tension as is possible with most forms of screw joints. This type of joint leaves little or no projection on either the outside or the inside of the pipe, and thus is well adapted to situations where there is small clearance or it is important to use as large a casing as possible to preserve working space. It is also helpful in reducing joint leakage to a minimum under conditions where high fluid pressure exists. However, joining pipe in this way is slower than when threaded joints are used and there is difficulty in maintaining alignment of the tubes. The personal element enters to a greater extent in determining the success of the casing operation, and the metal in the vicinity of the weld may become brittle as a result of localized heating.

The cost of a welded string of casing is about the same as that of ordinary collared-joint casing, the saving in cost of couplings and threading being approximately offset by the cost of preparing and welding joints. Welded joints are helpful in inserting liners in undersized holes where there is little clearance, and they have also been used successfully in redrilling jobs where it has been necessary to sidetrack a column of casing—a condition that might lead to interlocking of couplings on the two strings if coupling joints were used. In some fields where the producing formations are unconsolidated, caved material tends to pack about the couplings of collared joints and make subsequent removal of the liner difficult, particularly if the hole is crooked. Much of this difficulty is avoided by use of welded joints. In some California wells, welded strings of 8¼- and 10-in. casing, 1,100 ft. in length, have been successfully inserted in wells of moderate depth.

Welded Slip-joint Casing.—Various types of slip-joint casing are occasionally used in oil-well service, principally in casing off surface formations (see Fig. 153). The larger sizes of collared-joint threaded casing are unnecessarily heavy and expensive and economy is possible through use of thin-walled conductor casing equipped with bell-and-spigot slip joints. This is available in sizes up to 22 in. in random lengths of 35 to 40 ft.; on insertion into the well, the joints are spot-welded with the acetylene torch, through holes bored through the outer or "belled" portion of the joint. Or fusion metal may be applied circumferentially between the beveled end of the bell and the wall of the inserted end. Fusion metal applied in this way carries the load in shear and is not so secure as when it may function in tension. There is no advantage in space conservation in this type of casing.

In another type of slip-joint casing designed for welding, the ends of two tubes butt together inside a close-fitting collar, previously welded to the end of one tube in the tube mill. In the field, only one weld need be made. This type of welded

joint maintains good alignment and preserves a flush interior surface and a close fit between welded elements.

Protective Welding of Joints Secured Primarily by Other Means.—Some operators make a practice of spot-welding the couplings on ordinary threaded-joint casing to prevent the joint from loosening in the well as a result of repeated stress or vibration. Sheet-metal casings, described in a later section, are sometimes spot-welded for added security in preventing them from pulling apart.

Sheet-metal Casings

Riveted casing or "stovepipe" is made of thin sheets of wrought iron or steel, rolled into cylindrical form and riveted at the seams (see Fig. 154). The individual joints are 2 or 3 ft. long and are usually made of two sheets of metal, one cylinder within another, and so placed with respect to each other that the end of one cylinder is just opposite the center of the other. This results in the inside cylinder projecting for half its length at one end, leaving a corresponding recess within the outer cylinder at the opposite end. When such joints are telescoped together, the projecting inside sheet of one joint is forced into the center of the outside sheet of another, until the inside sheets of the two joints butt together. The result is a continuous, double-walled cylinder. Considerable friction develops between joints when they are forced together, and it is common practice to increase this by denting the outer cylinder against the inner with the point of a sharp pick. The frictional contact between joints, thus developed, is often all that is provided to hold them together. Occasionally however, when a long column of stovepipe is to be placed in a well and

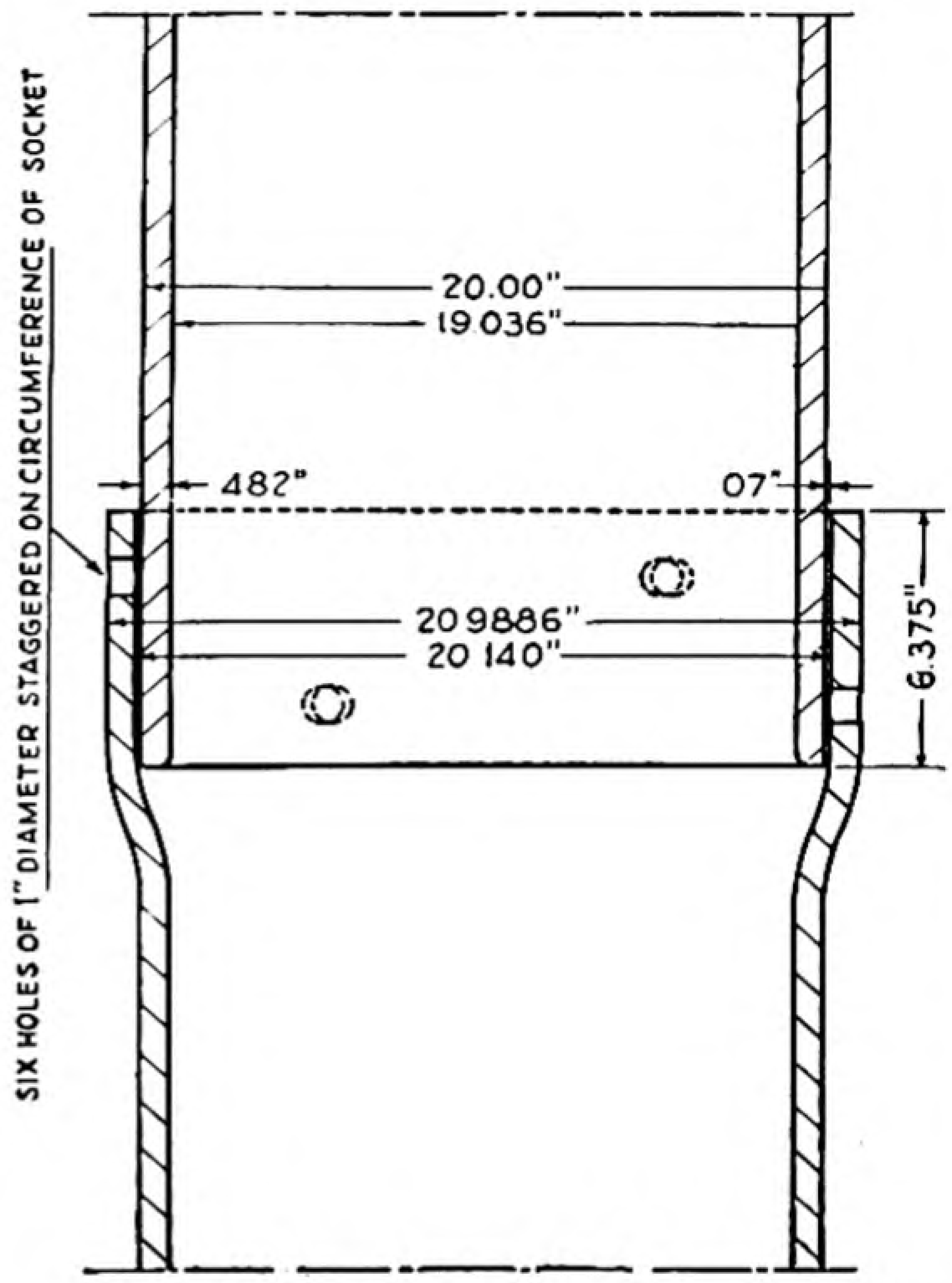


Fig. 153.—Astco slip-joint conductor casing. Dimensions given are for 20-in. outside diameter, 104-lb. casing.

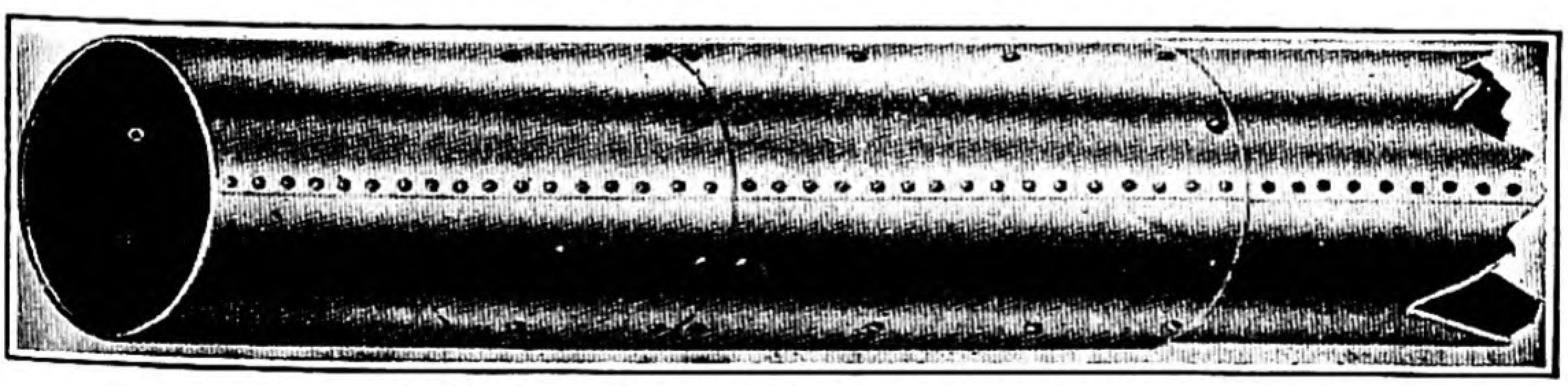


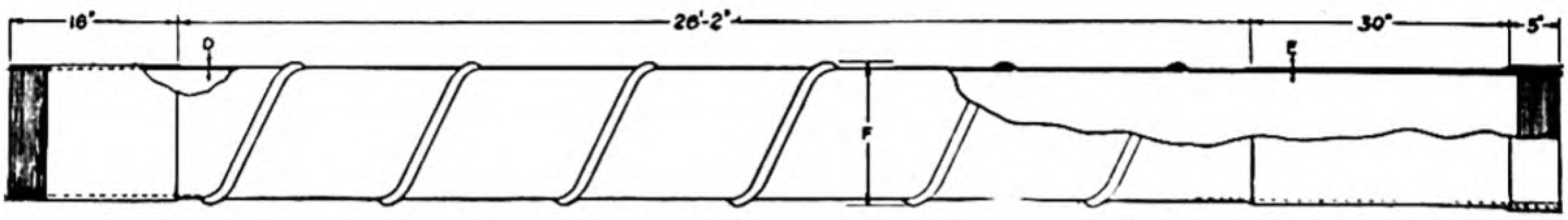
Fig. 154.—Riveted casing or "stovepipe."

there is danger of the column pulling apart under its own weight, the joints will be riveted together. This is accomplished by lowering a close-fitting mandrel inside the pipe to serve as an anvil, and driving the rivets through holes previously drilled and countersunk on the inside. Modern methods of electric riveting greatly facilitate this operation.

Riveted casing is generally used in wells of large diameter, say, 12 in. or greater, though it may be had in sizes as small as 4 in. Sizes up to 20 in. are regularly carried

by manufacturers, and larger sizes may be made to order for wells of exceptional diameter. In the Russian fields where, in years past, this kind of casing was used almost exclusively, casings as large as 36 in. were not uncommon. The metal sheets used in forming stovepipe vary from $\frac{1}{8}$ to $\frac{5}{16}$ in. in thickness, the sheets being cut to proper size and all rivet holes punched and countersunk before the cylinders are rolled. The pipe, ready for insertion in the well, may be had from manufacturers either in single joints or in made-up sections ranging in length from 10 to 21 ft., the individual joints making up each section being riveted around circumferential joints as well as along the seams. Riveted casing is not ordinarily watertight, though it can be improved in this respect by careful calking of all seams and joints. However, it is not ordinarily heavy enough to withstand any great hydrostatic head that may build up in wet formations.

It is customary to reinforce the first joint (or "starter" joint) of a column of stovepipe, either by riveting on a steel shoe or by constructing it of three or four sheets of metal instead of two. The latter type of reinforcement is generally preferred because of the smaller clearance necessary. Such reinforcement assists in preventing



(*Courtesy of Naylor Pipe Co.*)

FIG. 155.—Spiral-weld sheet-metal casing.

abrasion and distortion of the lower end of the pipe by contact with the walls of the well.

Riveted casing is intended only for light service and is seldom used at greater depths than 800 ft. because of its tendency to pull apart under its own weight. However, single columns of 16-in. stovepipe over 1,000 ft. long have been placed in wells under favorable conditions. When once started into a well, a column of stovepipe usually cannot be raised if there is friction against the walls. It can be driven only lightly because the joints have a tendency to telescope and buckle; or, if the lower end of a column is hanging freely in the well, it may be jarred off by the resulting vibration. It is easily deformed by pressure from the walls or in passing through a "flat" hole. The chief advantages of riveted casing are its smooth exterior surface, small space occupied in the well and lower cost. Because of its smooth exterior surface, it is particularly adapted to casing off loose, sandy surface strata which tend to cave and bind around the couplings of collared-joint casing. Loss in effective working diameter within the well is reduced to a minimum through use of this type of casing.

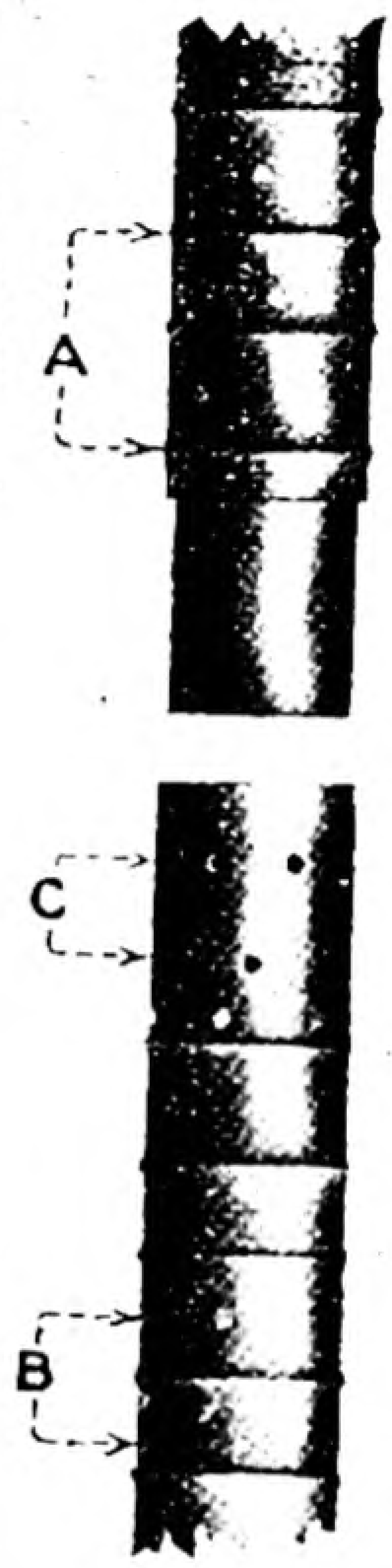
Spiral-weld Sheet-metal Casing.—Still another variety of sheet-metal casing suitable for surface strings is a watertight spirally welded pipe with integrally formed threaded joints (see Fig. 155). Maximum structural strength with minimum weight is claimed for this pipe. Also, the spiral bead on the exterior surface of this pipe tends to center it in the well and assists in distributing cement about it when the annular space is to be filled with fluid cement, as is often required in anchoring surface casings to the formation and in excluding surface waters.

Corrugated Sheet-metal Casing.—Circumferential corrugations in a sheet-metal casing stiffen it and give additional security against deformation or collapse, and surface strings of this type have been popular in some districts. Hercules casing (see Fig. 156) has been used to some extent in the California fields, where surface strings ranging from 16 to 30 in. in diameter must sometimes be set at depths as great as 1,200 ft. This is a heavy, sheet-metal casing in which the seams are welded

and the individual joints are held together by a patented type of welded rivet; circumferential corrugations in the sheet metal give added strength. It is available from the manufacturers in 20-ft. lengths which are riveted and welded together as they are lowered into the well. Casings of this and other special types, requiring unusual facilities in handling, are often assembled and placed in the wells on a contract basis by experienced welding crews in the employ of the manufacturers.

Corrosion-resistant Casing

In some fields, casing and tubing in oil and gas wells are subjected to highly corrosive conditions that result in rapid destruction of the pipe metal. Where the oil and gas contain hydrogen sulphide or sulphur dioxide, or where ground waters in contact with the casing or tubing are highly saline, steel pipe is rapidly destroyed. Protection against corrosive influences may be gained by addition of a small percentage of copper, nickel or chromium to the steel during the process of manufacture. Wrought iron is claimed to be superior to steel in corrosion resistance and this is one of the reasons for its preferential use by some oil producers in situations where its strength is adequate. Other methods of protecting casing against corrosion involve application of protective surface coatings or use of corrosion-resistant linings. Various paints and bituminous coatings are frequently used in protecting buried steel pipe lines; metallic coatings, particularly zinc, have been widely used for this purpose. However, pipe coatings are likely to be ineffective on well casing because they are largely scraped off or worn away by friction against the wall of the well and by contact with other casings and drilling equipment. Yet, some sheet-steel casings used in surface strings are galvanized.



(Courtesy of Union Tank and Pipe Co.)

Fig. 156.—Hercules conductor casing. *A*, corrugations giving security against lateral stress; *B*, button welds; *C*, shop-punched holes for welding.

"Neat" portland cement, placed in a fluid condition in the annular space between the exterior surface of a column of casing and the wall of the well and allowed to set and harden, forms a highly impermeable sheath about the casing that greatly extends the life of the steel where corrosive influences are present. For inside protection against corrosion by fluids passing through well casing or tubing, a thin lining made of cement or other corrosion-resistant material may be used. Duroline casing, of this type, has a "neat" cement lining of about the same thickness as the metal wall of the pipe. In conjunction with plastic sleeves between the ends of the tubes in the coupling, full inside corrosion protection is gained. Casing of this type has been used to advantage in brine injection wells in the east Texas and other Mid-Continent fields.

Fiber Casing.—A variety of casing made of macerated wood fiber and reclaimed paper pulp in a matrix of coal tar, molded and compressed into tubular form and held together by tapered friction joints, has been used to a limited extent for surface strings in shallow wells. For example, at a time when steel casing was rationed among oil producers, a string of 427 ft. of 4⅛-in. I.D. fiber conduit, with single lengths of steel casing at top and bottom, was used as a surface string in a shallow Illinois well. A special cementing shoe permitted pumping cement down through the casing and back to the surface through the annular space about it, thus forming a complete

cement sheath about the pipe. Although noncorrosive, the resistance of fiber pipe against bacteria and other disintegrating influences has yet to be demonstrated.

Drillable-metal Casing.—Aluminum or magnesium alloys may be used in construction of certain portions of a casing string that are intended to be removed at a later time, after the casing is in position in the well. For example, it may be desired to cement a liner in a well and then remove "windows" from it opposite intervals in which productive oil sands are logged. Or it may be anticipated that the entire liner may have to be drilled up in subsequent redrilling or deepening operations. Securaloy, developed for this purpose, weighs only about one-third as much as steel, yet has an ultimate strength of 39,000 lb. per sq. in., a yield point of 33,000 lb., and is highly ductile. It can readily be machined or cast in various forms and threads may be cut on it. Yet, with expanding reamers or wall-scraping tools or drag bits, it may readily be broken up into small particles and circulated out of the well. This alloy is also highly resistant to corrosion, particularly in the presence of fluids containing sulphur, saline ground waters and acid reagents.[39]

CASING APPLIANCES

Installation and manipulation of casing in the well and within the derrick require the use of a variety of special appliances worthy of brief description. These include casing elevators, hoisting blocks, casing hooks and spiders for lifting, lowering and suspending a column of pipe; casing shoes attached to the lower end of a column of pipe to aid it in cutting its way through projections on the walls of the well and to reinforce the lower end of the column against damage thereby; casing tongs for screwing sections of pipe together; drive heads and clamps used in driving casing into a tight hole; and casing jacks useful in applying a powerful lifting force to casing that has become partly frozen by friction against the walls of the well. In addition to these, there are numerous other devices, some of which are described below, while others pertaining particularly to fishing operations are reserved for Chap. XIII.

Casing Shoes.—It is customary to place on the outside of the bottom of every column of casing lowered into the well a reinforcing shoe of steel, specially formed to prevent distortion and abrasion of the pipe, and to aid it in cutting a way for itself past minor obstructions on the walls. The lower end is beveled to a blunt cutting edge on the outer circumference. Casing shoes are somewhat larger in outer diameter than the collars on the casing to which they are attached, in order to ensure free passage of the pipe for any opening through which the shoe has passed. They are usually about 1 in. thick, from 10 to 16 in. long and weigh in the case of the larger sizes from 100 to 200 lb. There are several patterns (see Fig. 157) some of which are designed to screw on the bottom joint of casing, while others are shrunk on. The Texas pattern is both screwed and riveted to the casing. The Baker shoe has a series of square teeth cut on the lower end. By rotating a casing equipped with this shoe, the casing is capable of cutting a way for itself past minor obstructions. When pipe is to be worked down through hard rock, such a shoe offers a considerable advantage. The material used in the manufacture of casing shoes is preferably a good grade of hardened plow steel. Casing shoes designed to screw on the casing usually have a narrow recess, turned in the upper end above the threads, and a shoulder below the threads. The casing screws into the shoe until it butts against the shoulder,

and the annular space above the threads formed by the recess between the casing and the shoe is filled with molten lead or babbitt metal. This strengthens the screw joint and prevents the shoe from becoming detached in the well. The shoe provided must be especially heavy when driving of the pipe will be necessary.

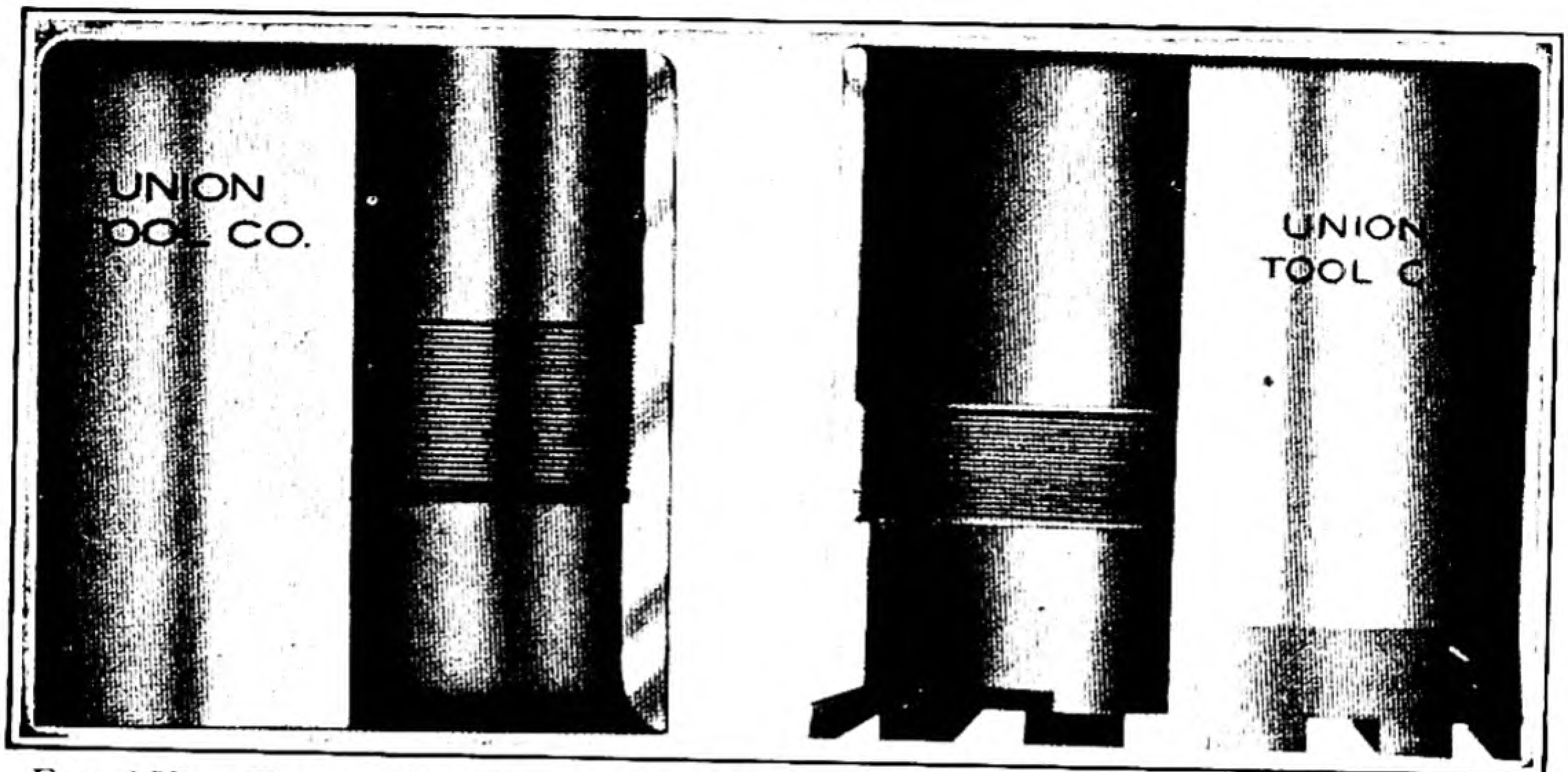


FIG. 157.—Types of casing shoes. Left: common form. Right: Baker shoe.

For use in the unconsolidated formations of the California fields, some operators construct unusually heavy and long casing shoes by shrinking short sections of heavy tubular steel on a joint of casing and dressing the outer surface to a slight taper with a blunt cutting edge at the lower end.

Cement Float Shoes.—Special types of float shoes are available, which are designed to serve the triple functions of reinforcing the lower end of the column of casing, preventing the well fluid from entering the casing so that it may be "floated in"—thus relieving the surface equipment of a large part of the dead load—and facilitating the operation of cementing a column of pipe after it is in place in the well. A sectional view of a type of float shoe popular in the deeper California fields is presented in Fig. 158. In this case, the lower end of the casing shoe is filled with concrete, molded to form a hemispherical guide which projects below the shoe. Passages through the concrete and a spherical valve and disk seat permit movement of fluid through the shoe in a downward direction only. The valve is of composition material so that it is lighter than mud fluid and is buoyed upward against its seat by the fluid pressure.

(*Courtesy of Baker Oil Tools Co.*)
FIG. 158.—Baker cement float shoe.

Another type differs from the one illustrated in that it has side outlets instead of a bottom outlet. The side outlets are advantageous when the shoe rests on bottom, in permitting free flow of mud fluid and cement out of the casing during subsequent cementing operations. The concrete and composition valve and seat can be readily drilled up with the tools on resuming drilling operations to lower depths.

Casing Elevators.—In lifting or lowering a joint or column of casing suspended vertically, it is necessary to provide some sort of clamp which will grip the pipe securely, to which the necessary hoisting tackle may be attached. The device usually employed for this purpose is called a "casing elevator" and is so designed that it may be clamped loosely around the pipe below the top collar, the weight of the pipe resting on the lower edge of the collar.

The elevator finds constant use when casing is being inserted into a well, each new joint being lifted from the derrick floor and suspended on the elevator until

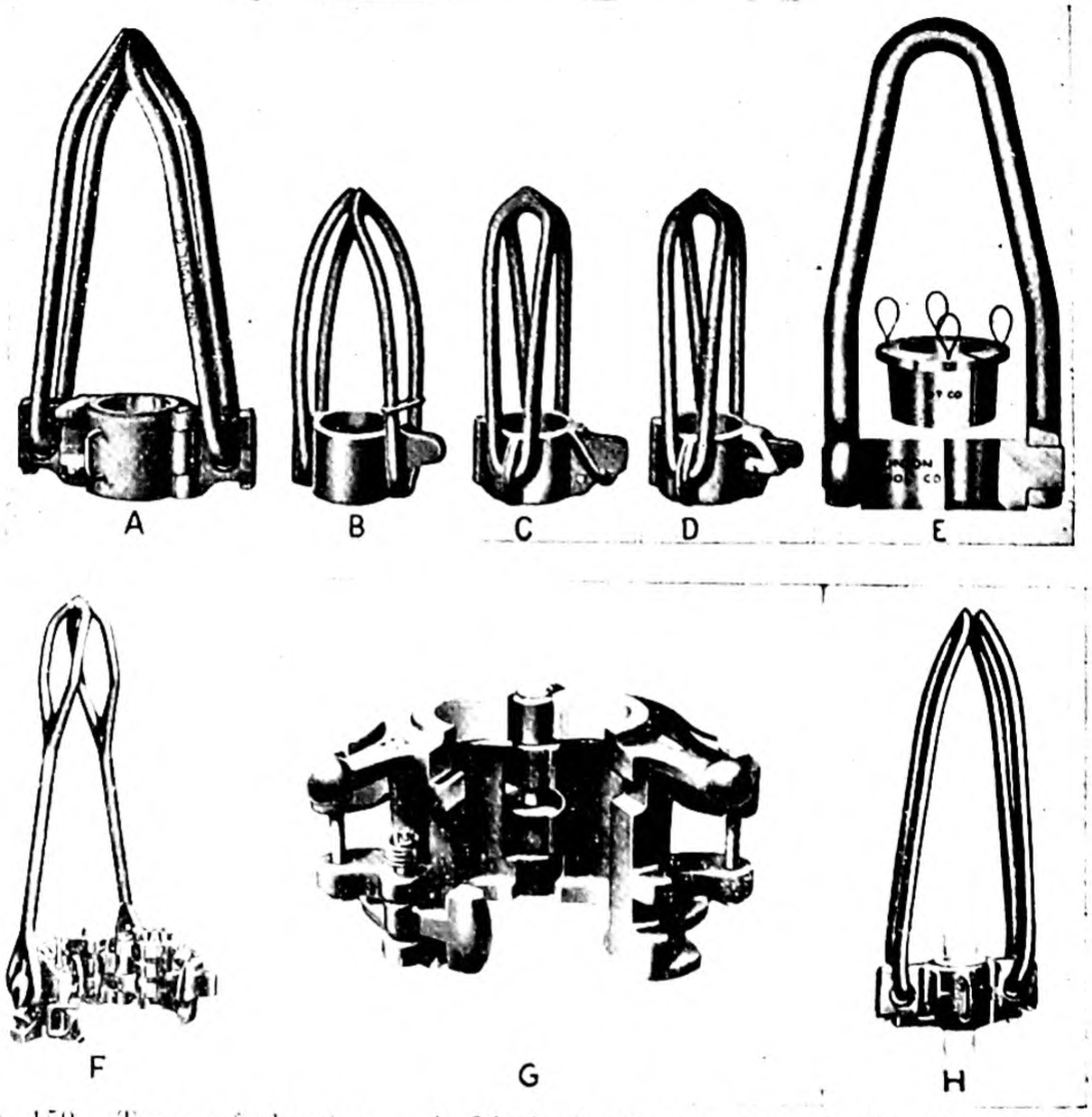


FIG. 159. Types of elevators. *A*, Ideal; *B*, Mannington; *C*, Fair-Mannington; *D*, Fair; *E*, single link; *F*, *G* and *H* are types of Byron-Jackson elevators; *F*, side-door type equipped with slips and weldless suspension links; *G*, Wilson type, center latch, and *H*, side-door type.

it is screwed into the collar of the preceding joint, after which the entire column is lowered while suspended on the elevator. Such service requires an elevator that can be rapidly clamped and unclamped and which suspends the casing vertically so that it can be freely rotated while being screwed into the collar below. It must be of adequate strength to support the weight of the entire column of casing, which may in a long column of large-diameter pipe aggregate 200 tons or more. It is imperative, under the conditions pertaining, that the elevator be so designed that it offers adequate security against accidental opening of the clamps and dropping of the casing while under strain.

Several different patterns of elevators have been designed and are available on

the market, differing from each other chiefly in the manner of latching in the locked position. The Fair, Mannington, Ideal "B-J" and Wilson patterns are well-known and commonly used types (see Fig. 159). It will be noted that in each case there is a pair of semicircular clamps hinged at one side and provided with a locking device of some sort at the other. There is also a pair of heavy links, suitably curved to bring the point of support over the center of the pipe, passing through holes in heavy lugs attached to the side of the clamps. The inside diameter of the clamps is slightly greater than the outside diameter of the pipe for which it is intended. One type of elevator has a single link instead of two. The body of the elevator is in this case in one piece and has an opening through it which permits of its passing freely over the casing collar. With the elevator just below the top collar, a split bushing of proper size is slipped into the elevator and around the pipe, furnishing the means of applying a lifting force under the collar. Casing elevators are made of wrought iron or steel and are necessarily of heavy construction, ranging in weight from 200 to upward of 2,500 lb. in the larger sizes of the heavier models. In addition to their use in handling casing, they find application in coupling and uncoupling rotary drill pipe (see page 306) and oil-well tubing.

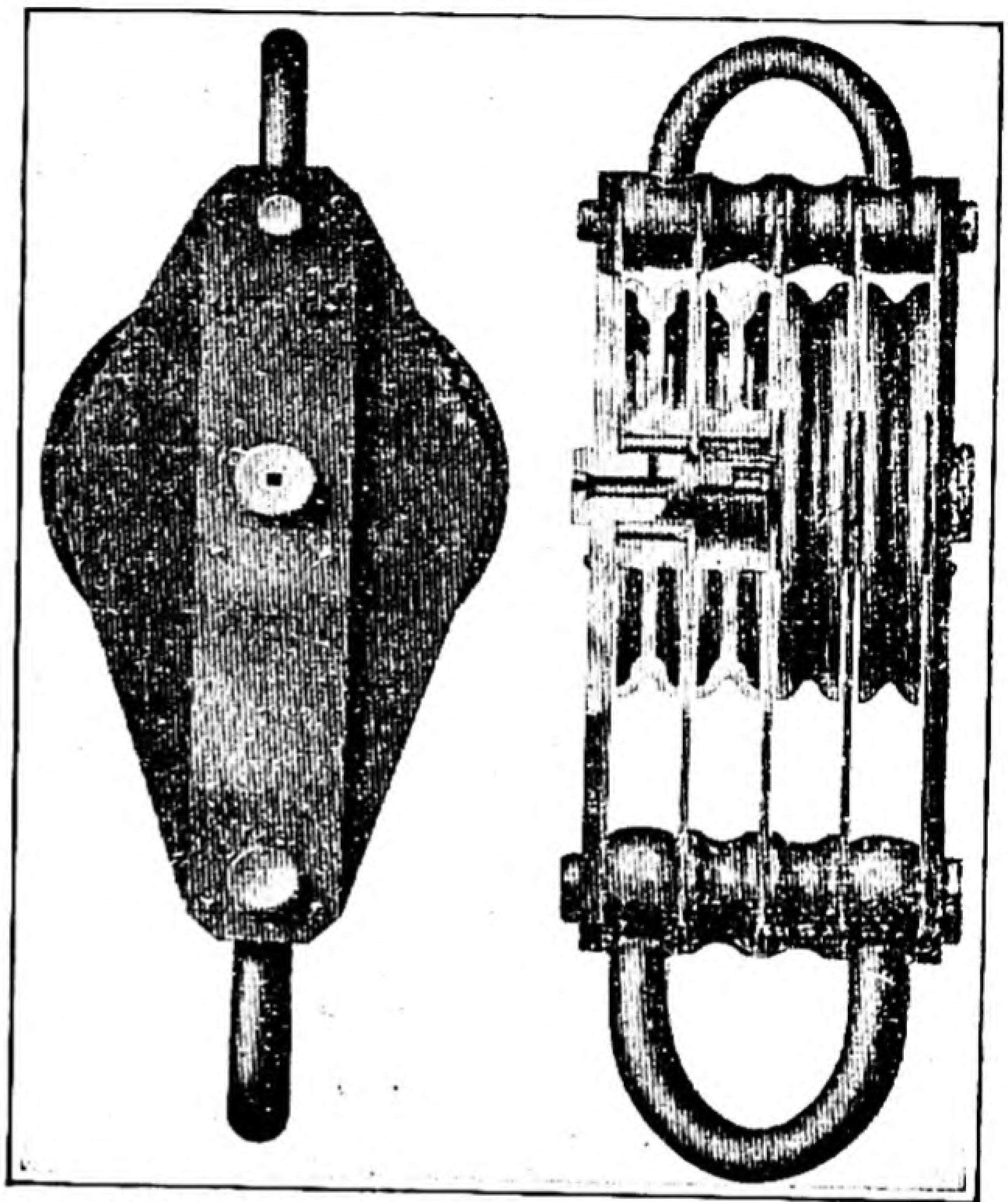


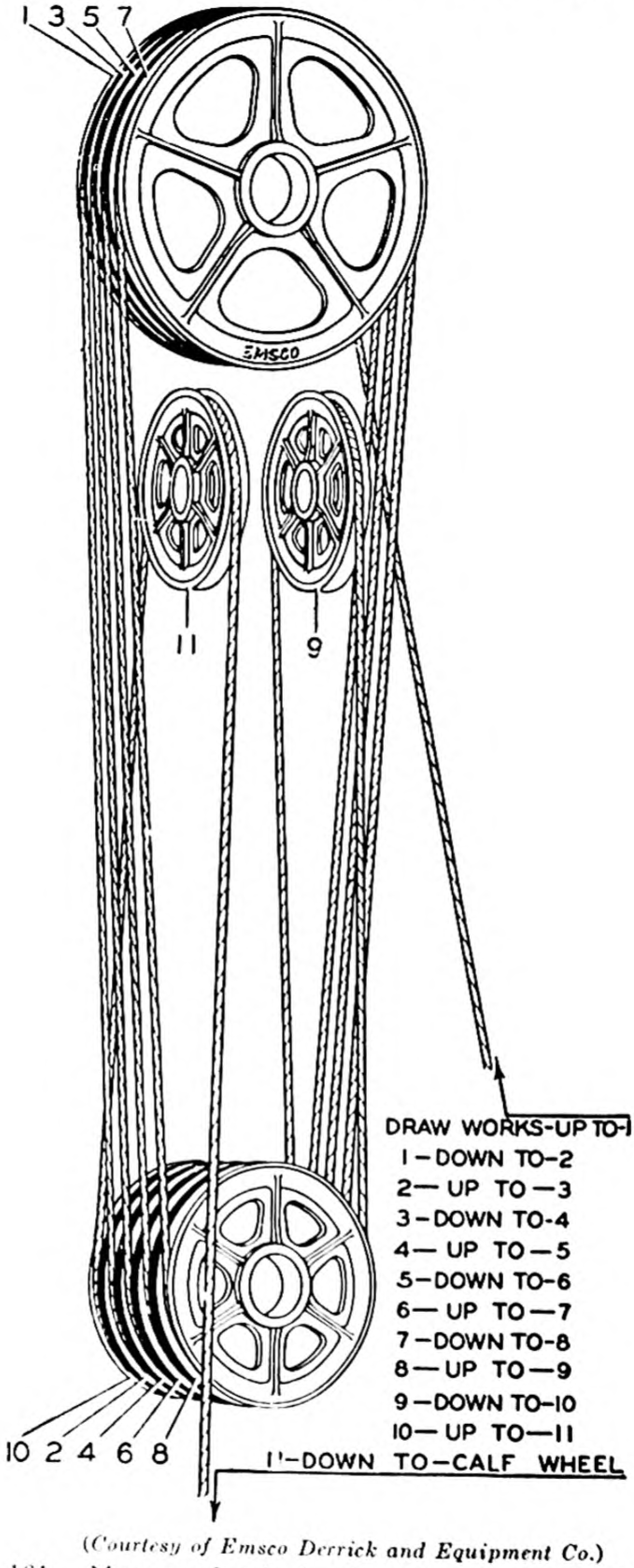
Fig. 160.—Four-sheave roller-bearing traveling block.

Casing Blocks or Hoisting Blocks.—The mechanical advantage necessary in handling a long string of heavy casing is secured through the use of a hoisting block containing from one to five sheaves, the calf or casing line being threaded between these and two or more sheaves at the derrick crown. The sheaves range in diameter from 10 to 26 in. and are supported by a heavy metal frame from 18 to 48 in. long, consisting of plates separating the sheaves and spaced apart by cylindrical spools, held together by three bolts, one of which, equipped with a loose bushing, serves as a shaft for the sheaves to turn on (see Fig. 160). A bail or link at both top and bottom provides a means of attaching ropes or hooks. Casing blocks should have a low center of gravity so that they do not turn over when the load is applied.

The mechanical advantage secured will depend upon the number of lines used and the method of stringing. The power applied at the calf-wheel drum will be multiplied as many times as there are lines strung between the hoisting block and the derrick crown, and the hoisting speed will be correspondingly diminished. Usually the end of the casing line or dead line will be attached to the top bail of the casing block, though in the case of the combination rig the other end may be attached to the draw-works hoisting drum. Figure 161 illustrates the usual manner of stringing a double-deck crown block and five-sheave casing block with eleven lines. If fewer lines are desired, one or more of the pulleys may be left unstrung.

Casing Hooks and Links.—The elevators are suspended from the lower bail of the hoisting block by a massive hook and a heavy split link or C hook (see Fig. 162). The larger sizes of casing hooks weigh as much as 500 lb. The hook must be free to

turn in its supporting trunnion so that the casing can be rotated while suspended on the elevators without twisting the lines above the hoisting block. The bearing



(*Courtesy of Emsco Derrick and Equipment Co.*)
FIG. 161.—Manner of stringing five-sheave traveling block.

between the hook stem and the trunnion is often equipped with cone or ball bearings to eliminate friction, and in one type a spring is inserted to avoid the destructive jerk that otherwise results from sudden application of the power in lifting a column of

casing. A clevis is sometimes attached to the edge of the hook for connecting a small control rope. The hook illustrated in Fig. 162*C* is designed to support both the elevators and rotary swivel.

Casing Spiders or Wedge Blocks.—In handling casing in the well a means must be provided for suspending a column of casing from the surface in such a manner that

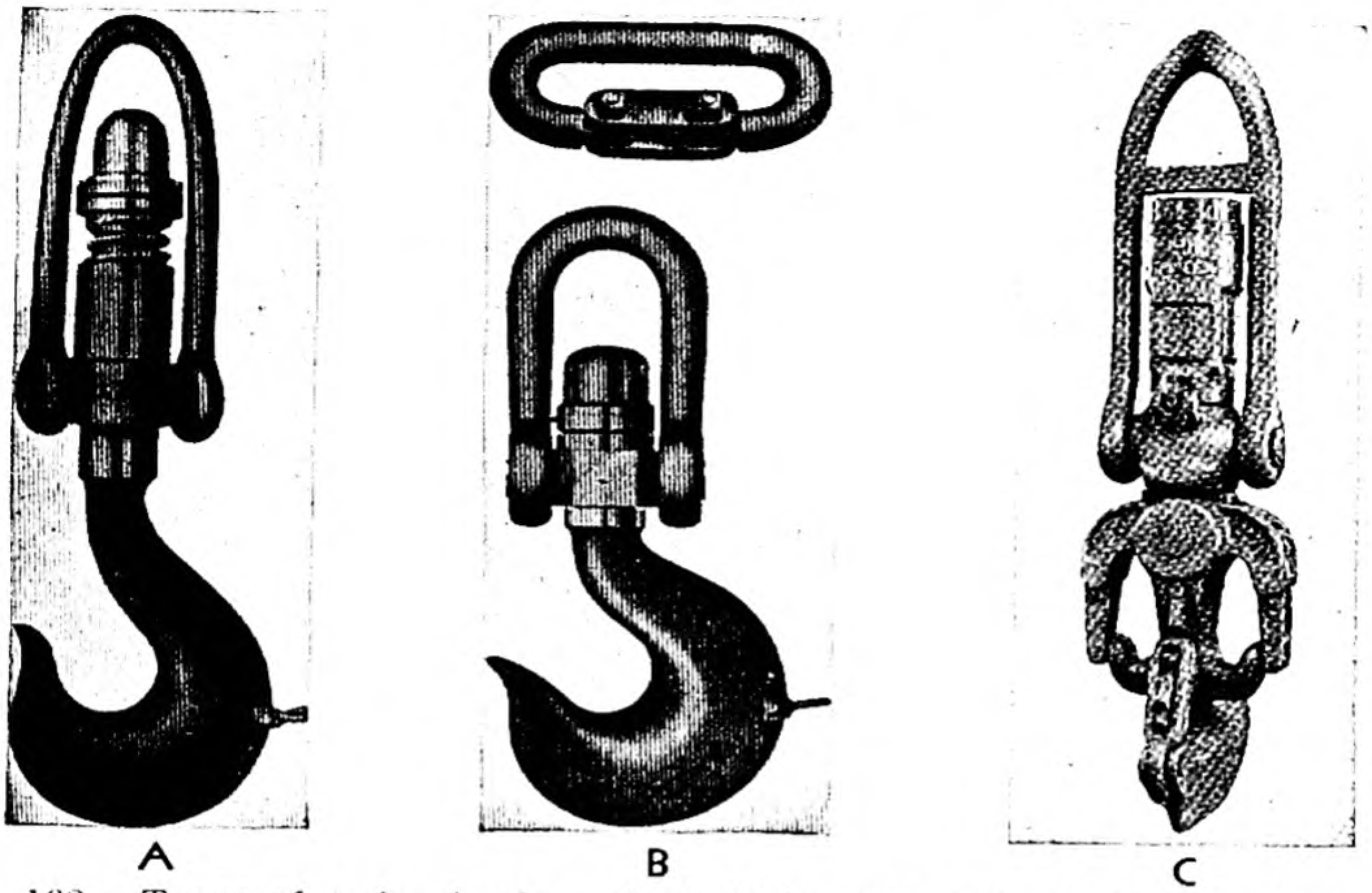


Fig. 162.—Types of casing hooks. *A*, "wiggle spring" hook; *B*, cone-bearing hook with strapped C-link; *C*, Byron-Jackson triple-suspension safety hook supporting both elevators and rotary swivel.

the open end of the casing is left free for drilling, bailing or other operations. For this purpose, a casing spider is used. This consists of a heavy forged steel ring with a conical hole through its center (*i.e.*, larger at the top than at the bottom) and two projecting lugs at opposite points on the circumference (see Fig. 163). The hole through the ring is large enough to admit the largest sizes of casing, and conical

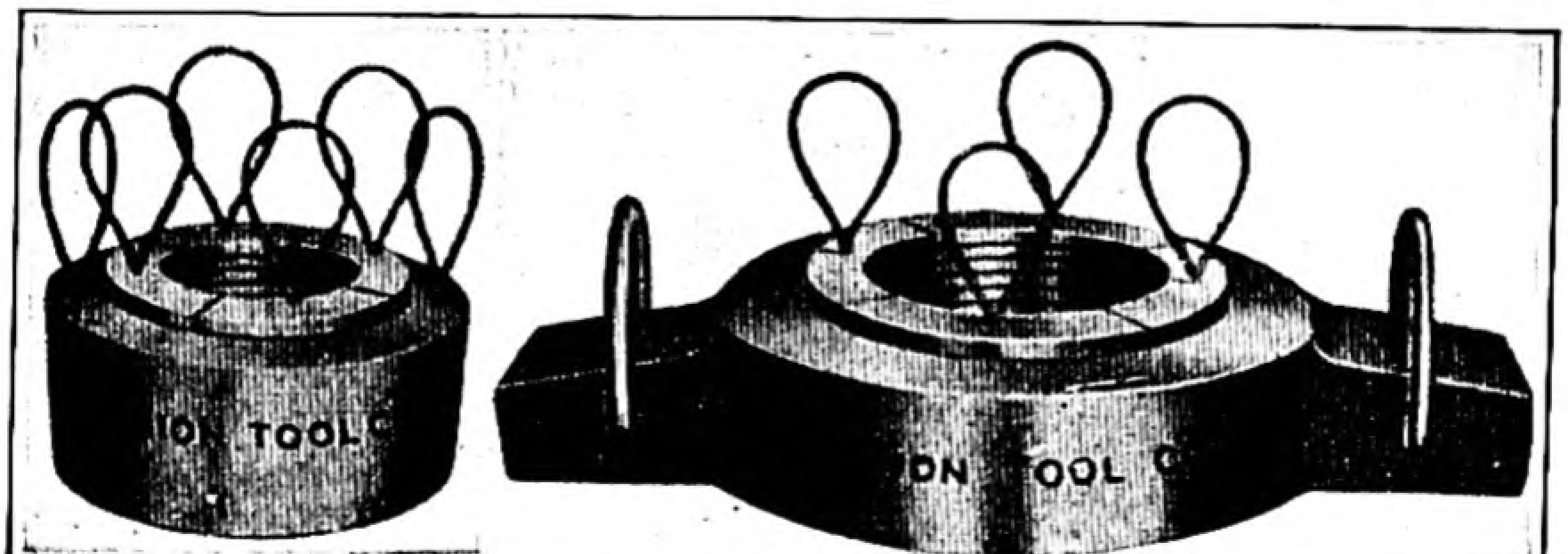


Fig. 163.—Casing spider with bushing and extra liner and slips.

steel liners are provided to adapt it to use with smaller sizes of pipe. Curved steel wedges, called "slips"—usually three or four in number—fit into the conical opening of the spider or liner in such a manner that when in position they form a cylindrical opening just large enough to admit the pipe. The inner edges of the slips are machined with horizontal serrated grooves. With the pipe suspended through the spider, the slips are dropped into position, and, as the pipe is slowly lowered, the slips slide down on their conical supports and are thus forced in against the pipe until the latter is

gripped securely. The greater the weight of the column of casing, the more securely it is held. To remove the casing from the spider, it is only necessary to lift the casing slightly and withdraw the slips. Wire-rope loops are provided on the ends of the slips so that they may readily be placed in position or withdrawn without danger to the operator. The spider may rest either on the derrick floor or on timber supports in

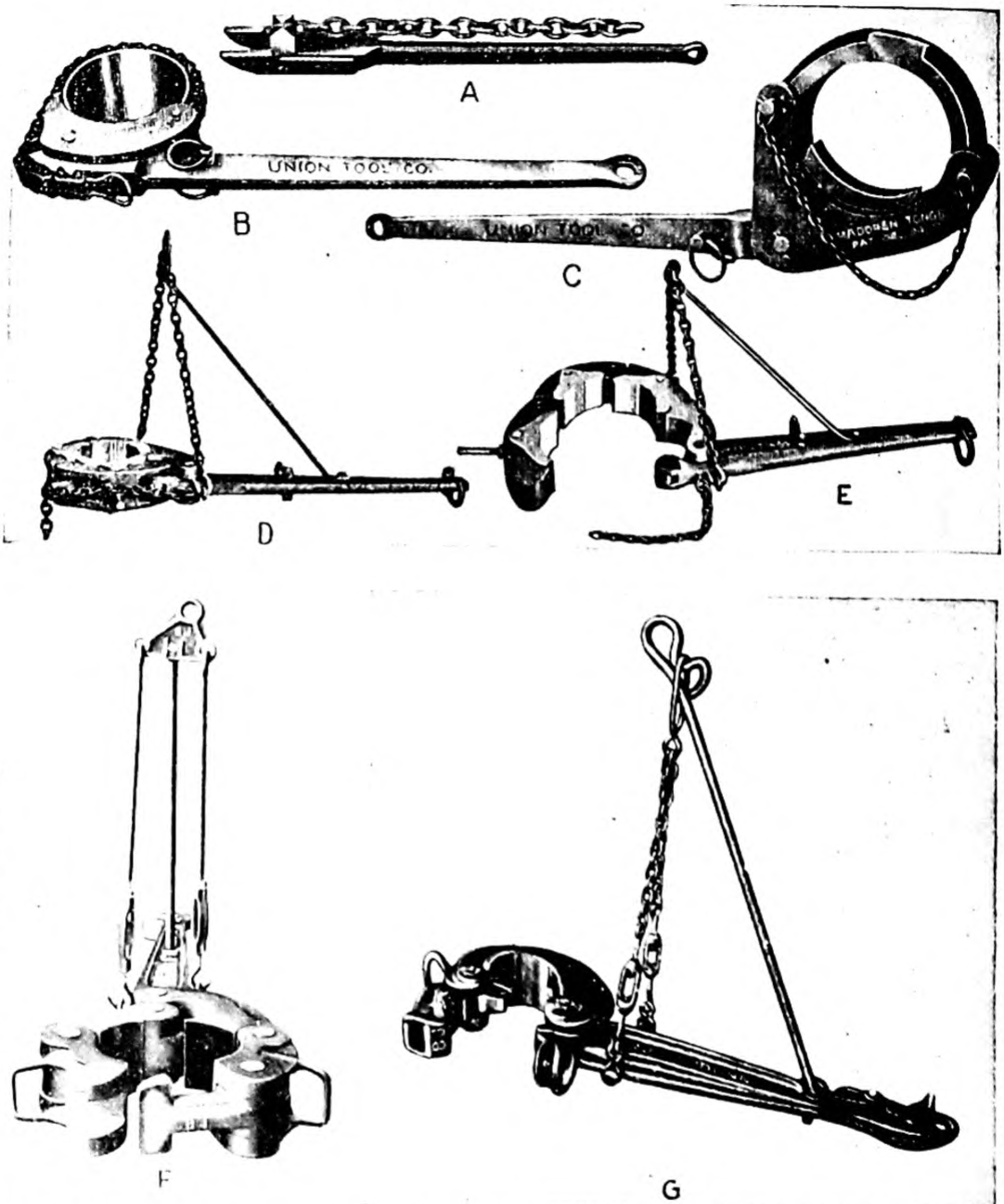


FIG. 164.—Types of casing tongs. *A*, Kellerman chain; *B*, Hardison; *C*, Maddren; *D*, Griffin tongs closed and *E*, open; *F*, Byron-Jackson Wilson type and *G*, Dunn.

the bottom of the cellar; or it may be supported on cables or rods passing through links attached to the lugs. The weight of a casing spider ranges from 475 to nearly 2,000 lb., depending upon the maximum size of pipe for which it is designed.

Casing Tongs.—For turning the pipe in coupling and uncoupling screwed joints, pipe tongs of special design are provided. There are two general types: (1) the hinged-jaw and (2) the chain tong. The former are generally preferred for heavy service because of their positive grip, quick release and ease of application. A number of representative forms are illustrated in Fig. 164. Because of the heavy duty imposed

upon them, casing tongs are necessarily large and heavy, the larger sizes weighing as much as 450 lb. Because of their great weight, it is necessary to suspend them in a horizontal position from a derrick crane or from a balanced beam in the derrick. The jaws of casing tongs are often equipped with bushings which adapt the same tongs to various sizes of pipe. Some models are reversible so that the pipe may be either screwed or unscrewed from one position of the tongs, that is, without turning the tongs over. This is accomplished by merely changing a metal pin controlling the leverage from one hole to another in the jaws.

Casing Wagons.—Before it is placed in the well, casing is usually stacked on the casing rack at one side of the derrick, and, as it is needed, it must be brought into the derrick and turned on end with the aid of the elevators. To aid in supporting and transporting the casing while it is in the horizontal position, two-wheeled casing wagons are provided, one to be placed at each end of the joint of pipe. One of these

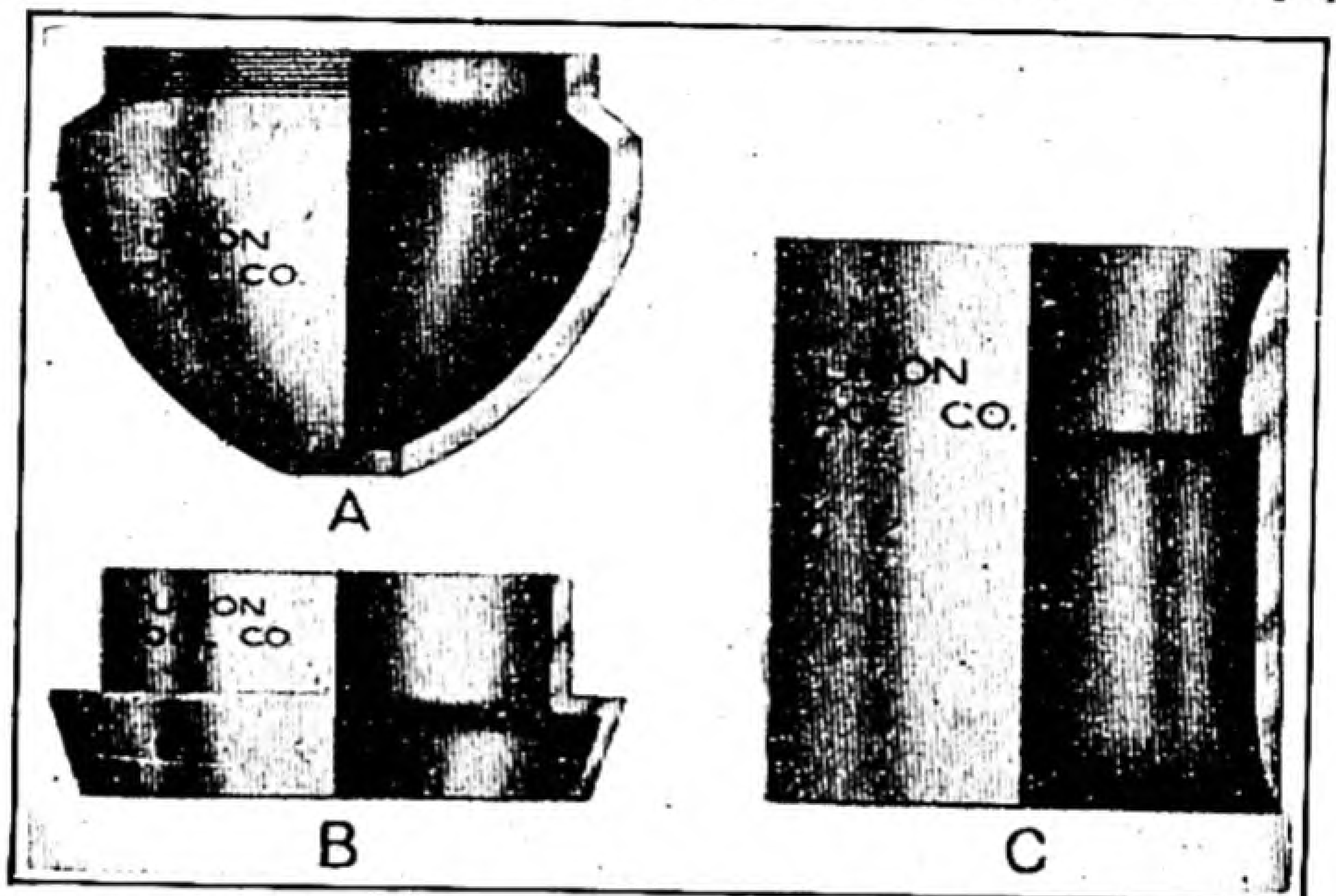


FIG. 165.—Floating plug *A*, shoe guide *B* and casing adapter *C*.

is equipped with a V-shaped support in which the front end of the pipe rests, and the other has a projecting hook which enters the rear end and, by depressing the handle, lifts the pipe from the floor. The wheels and carriages are made entirely of steel, with pipe handles. Wooden or steel dollies consisting of a solid roller mounted under a small supporting carriage are preferred by some drillers in transporting casing and drill stem from the casing rack into the derrick.

Casing Adapters, Shoe Guides and Floating Plugs.—When a string of casing in a well does not extend to the surface and a smaller string of pipe or tools must be lowered through it, there is danger of the tools or smaller casings "hanging up" on the upper end of the column. To avoid this, it is customary to place a casing adapter on the top of the column of pipe in the well, the adapter being beveled to guide the smaller string or tool through the opening (see Fig. 165*C*). Instead of this, or in addition to this, the shoe on the smaller string of pipe may be equipped with a shoe guide which serves the same purpose (see Fig. 165*B*).

In lowering a long string of casing into a well filled with water or mud, considerable strain may be taken off the elevators, spider and hoisting block if the lower end of the column be closed with a floating plug. In fact, if water is excluded from the casing, the buoyant force exerted is sufficient to float the column except in the case of the heaviest grades of pipe. Often, however, the well will not be full of fluid and the floating plug takes care of only a part of the total weight. The plug used is often hemispherical in form and is screwed to the bottom of the column of casing (see Fig. 165A). Being made of cast iron, it is readily broken up with the drilling tools when the casing has been "landed."

Drive Clamps and Heads.—When it becomes necessary to drive casing into a well, the cable drilling tools are generally used to provide the necessary impact. The tools are lowered into the well until the wrench square on the top of the drill stem is slightly above the top of the casing column. A pair of heavy clamps, with a square opening through them and held together by two bolts, is then clamped securely to the wrench square; the bull-wheel brake is clamped, a spudding shoe is placed on the drilling cable and a jerk line is connected from the spudding shoe to the wrist pin

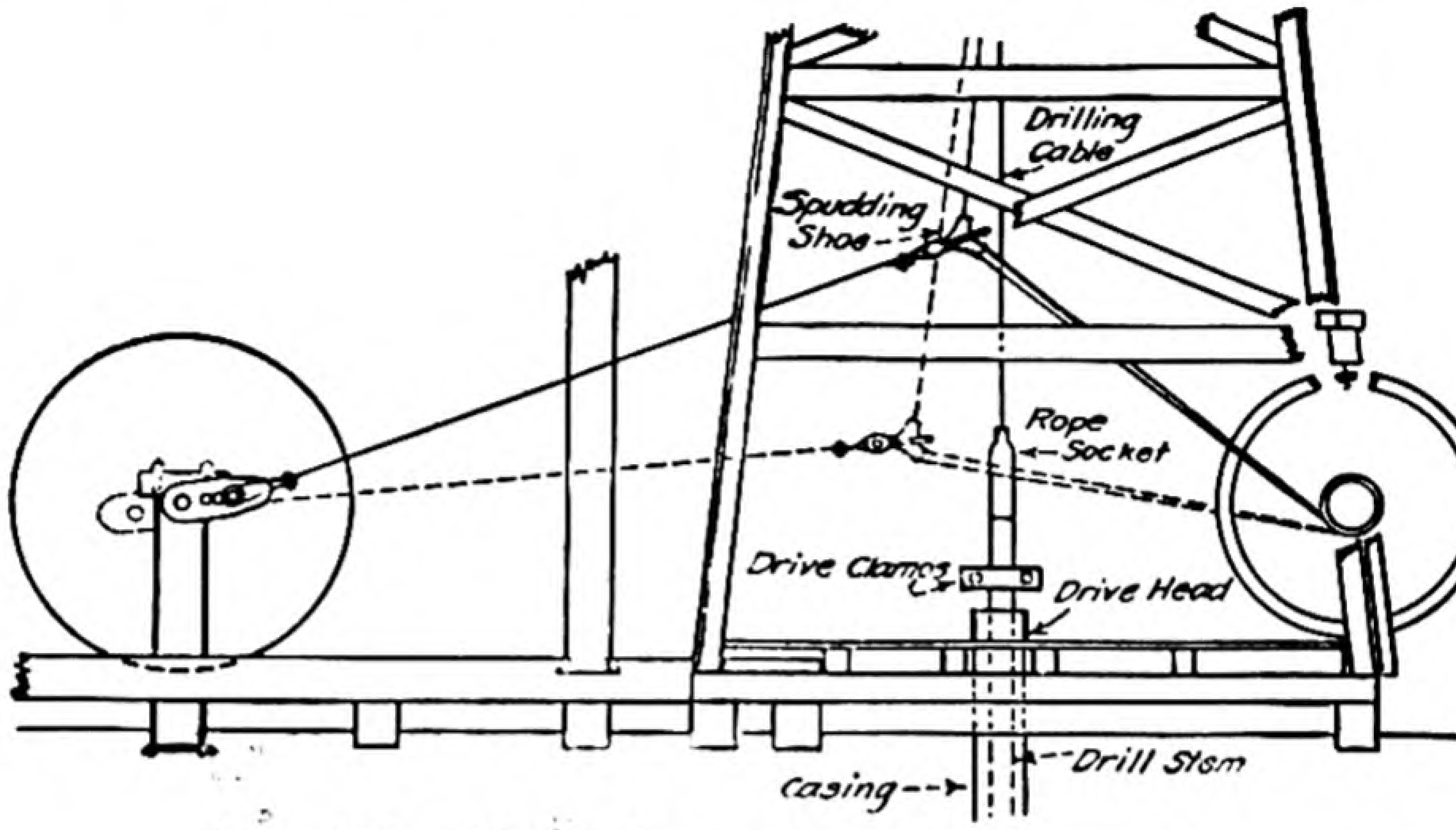


FIG. 166.—Illustrating method of driving casing.

on the crank (see Fig. 166). The clamps placed on the stem are of such size that they do not pass through the open end of the casing. With the tools operated as in spudding (see page 181), the full weight of the string of tools is allowed to fall on the top of the column of casing with each stroke, the drive clamps striking on a drive head, which has been previously screwed into the top coupling or on the top of the column of casing. Some types of drive heads are without threads and merely rest on the top of the column of casing. Typical drive clamps and heads are illustrated in Fig. 167.

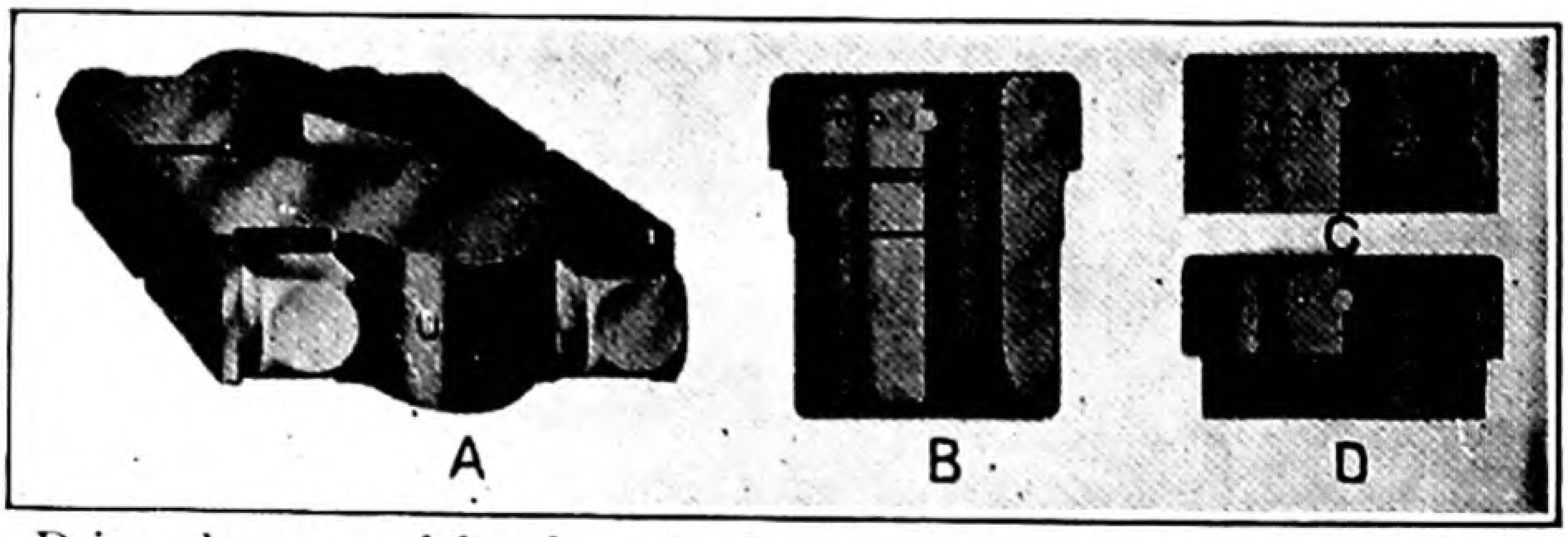


FIG. 167.—Drive clamps and heads. *A*, clamps; *B*, drop head; *C* and *D*, screw heads.

Casing Jacks.—In freeing partly frozen casing, or in pulling casing from a well about to be abandoned, a powerful lifting force is often necessary. The force of the engine, even as multiplied by the hoisting gear, is often inadequate, and recourse is had to the use of casing jacks. These are of two types: (1) screw jacks and (2) hydraulic jacks. With the principle of the screw and the hydraulic jack it is assumed the reader is familiar. The latter are the more powerful, some of those designed for oil-well service being capable of lifting a load of 250 tons. In either case the jacks are applied through the aid of a casing spider which grips the pipe, two jacks being used, one under each lug on either side of the spider (see Fig. 168).

In placing stovepipe in a well, instead of driving it, it is sometimes preferable to use the pressure of a casing jack in forcing the casing down. For this purpose, a stovepipe "push head" is placed on the top of the column and the jack applied, rigged to push against anchor clamps bolted securely to the derrick foundations.

Casing Testers.—When a string of pipe has been used to exclude water from a well, it is sometimes necessary to find the location of a leak admitting water. For this purpose, a swab casing tester is used. This consists of a small cylindrical receptacle closed at the lower end, with a leather disk of such a diameter as will fit snugly inside of the casing fastened around the top. A small bail permits of supporting the device on the sand line. Lowered to successively greater depths and occasionally withdrawn to the surface to note whether or not water has accumulated in the tube, the leak is soon located and the necessary steps taken for its repair.

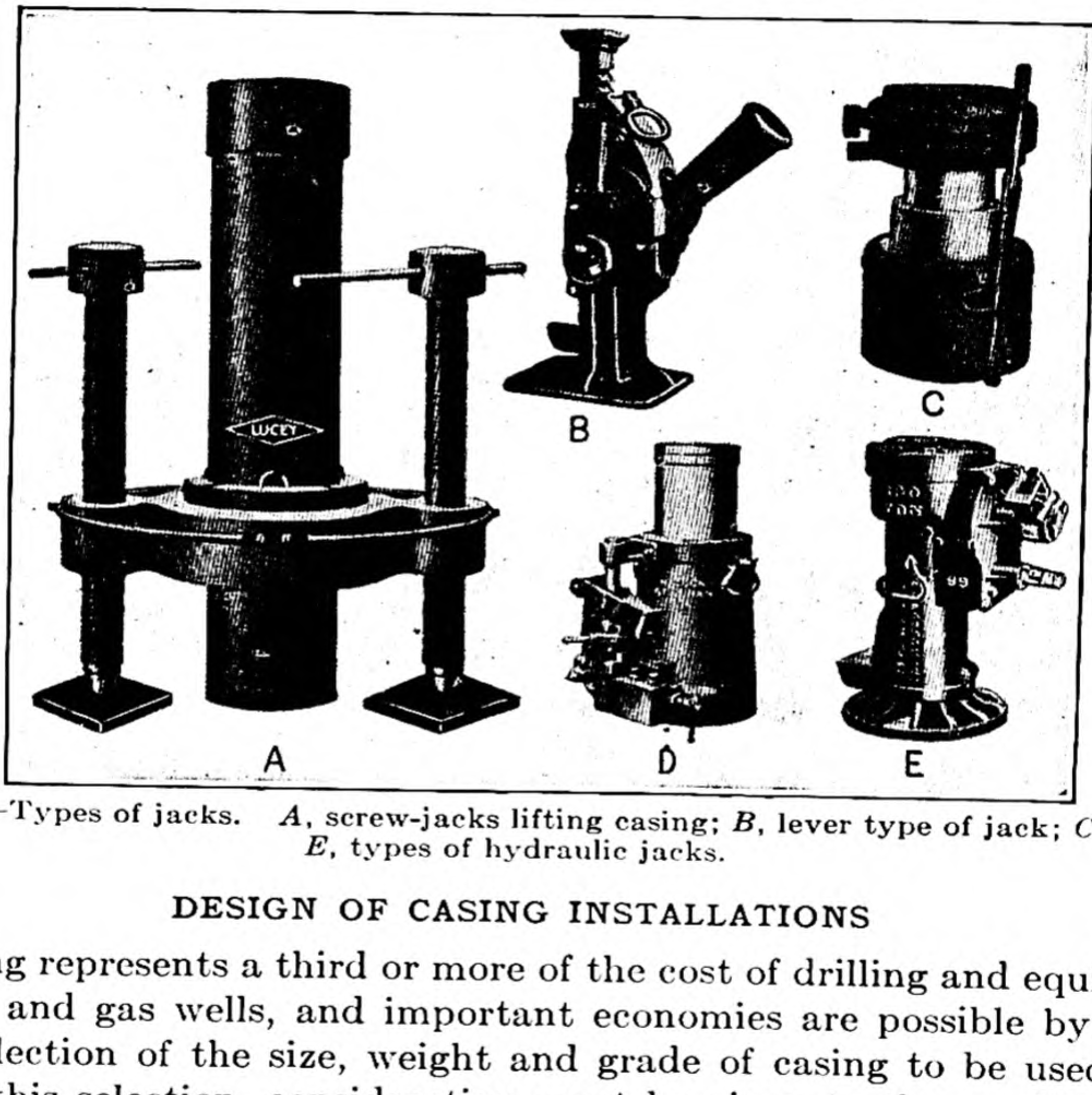


FIG. 168.—Types of jacks. *A*, screw-jacks lifting casing; *B*, lever type of jack; *C*, *D* and *E*, types of hydraulic jacks.

DESIGN OF CASING INSTALLATIONS

Casing represents a third or more of the cost of drilling and equipping most oil and gas wells, and important economies are possible by intelligent selection of the size, weight and grade of casing to be used. In making this selection, consideration must be given to the conditions to which the casing will be subjected during insertion into the well and subsequently, so that pipe of adequate size and strength and of suitable material may be prescribed. Often a well will be equipped with several strings of casing, each of different size, the smaller strings being telescoped concentrically within the larger. Each string has a definite purpose and as few will be used as possible not only because each additional string means extra expense, but also because of the loss in free working space in the well.

The number of strings necessary will depend upon formation conditions, depth of the producing formation, water-exclusion practices and method of drilling. Each water shutoff will ordinarily require a change in the size of casing. The method of drilling used and the depth to which it is possible to carry a string of pipe in the formations penetrated must also be taken into account in determining the number of strings to be used. With rotary drilling equipment in unconsolidated and semi-consolidated formations, much greater freedom in selection of lengths of individual strings is possible than when cable tools are used, because the casing is relatively free in the hole and there is less probability of accidental or unforeseen developments which prevent the carrying out of a prearranged program. If the well is a wildcat and the depth of the producing horizon and character of the formations to be penetrated are uncertain, it will be impossible to plan the casing installation definitely in advance; that is, changes in size of casing, determination of the location of water shutoffs, etc., must be made from time to time as the work proceeds. But in partly developed territory where the conditions to be met are approximately known, it should be possible, barring accidents, to select definitely all of the casing in advance and carry out its installation according to prearranged schedule.

The first column of casing may be a light, thin-walled "surface string," extending from the surface to a depth of but a few hundred feet and designed to support loosely consolidated formations near the surface; perhaps, also, to exclude surface waters. In a deep well, the surface string will also provide support for heavier and longer columns of pipe telescoped within it, and for security all of the annular space about it in the well may be filled with cement. The next smaller diameter column of pipe will ordinarily be a "water string," used primarily for the purpose of excluding water from the well, and is of heavy construction to withstand collapsing and other stresses. It should be watertight and is usually cemented to the wall of the well at its lower end and for some distance above. The next smaller column of pipe in the well may be an "oil string." Perforated where it passes through the oil-producing interval, its primary purpose is to support the walls of the well and confine the oil and gas so that they may not escape into overlying formations (see Fig. 169).

Conditions may require the use of more than one water string, and in deep wells a "protective string" may be used inside another to reinforce the concentric larger outer string against excessive collapsing force. There thus may be four or five strings of pipe used in a single well, rarely more. On the other hand, wells producing from firm sandstones and limestones that show no tendency to cave or disintegrate may be finished "barefoot"—*i.e.*, without any casing through the producing

interval. In such cases, two or sometimes only one may be used—a surface string and a water string, if needed.

Ordinarily all strings will extend to the surface where they are joined by a fluidtight casing head which closes the annular spaces between strings so that gas, oil, water and drilling fluid may be confined. Suitable valves control outlets from the spaces between strings and from the oil string. The outermost column of casing supports the casing-head assembly, which in turn, supports the inner casings (see Fig. 169). The perforated column of pipe extending through the oil-producing formation may extend only to the shoe of the next larger string, in which case it is called a "liner." In addition to the several columns of casing, wells are usually also equipped for production purposes, with a column of tubing of smaller size, through which oil is led to the surface. Mounted on this above the casing head will be suitable control valves and fittings permitting regulation of flow into the surface facilities and affording a means of shutting in the well when desired.

The diameter of each string of casing in a well will be determined after consideration of its purpose and its relation to other strings in the program. The size of the oil string will be determined by consideration of the probable productive capacity of the well and the method of production to be employed. The question of whether or not it will ultimately be necessary to redrill or

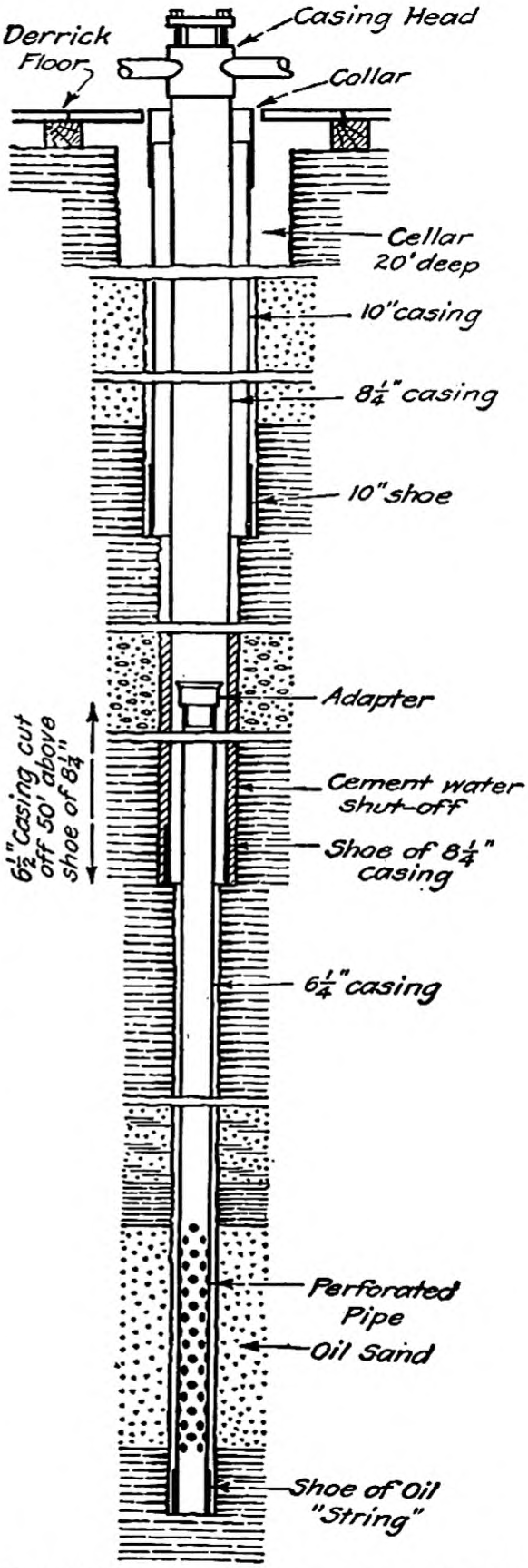


FIG. 169.—Manner of casing a well with three "strings" of pipe.

deepen the well to a lower producing horizon or to plug back to an upper zone will also be pertinent. Questions of economics enter in determining the relative merits of large finishing diameters versus slim-hole programs (see page 90). The sizes of the larger diameter water and surface strings will be determined by the diameter of the oil string and the necessary clearances that must be preserved between strings. The latter factor will depend somewhat on the type of casing used and the character of joints employed.

The weight or wall thickness of the casing and the quality of the material selected will depend upon the stress likely to be imposed upon it. A column of casing may fail to meet its requirements in a variety of ways. It may fail by tension under its own dead weight when suspended from its upper end. Failure may result by collapse from external pressure due to hydrostatic head of fluid in the annular space between the casing and the wall of the well when the lower end of the casing has been sealed in an impervious formation and the interior of the pipe is maintained under lower pressure. Collapse of casing may also occur as a result of earth pressure developed by heaving or shifting formations. Casing may fail by bursting under excessive internal pressure, applied perhaps during the process of "squeeze cementing" (see page 471). If a column of pipe rests on the bottom of the well or is "frozen" against the walls at some point and there are cavities about it above the point of support, it may fail by "column action" if the weight is not supported at the surface. Casing may be subjected to bending stress by a crooked hole or by shifting formations. If excessive earth pressure is developed and the pipe is rigidly supported opposite the point at which pressure is applied, it may be crushed. Casing may also fail by stripping of threads or pulling apart at the joints—a form of failure particularly likely to occur if the pipe is also subjected to bending. Stresses of considerable magnitude may be developed in a column of casing due to expansion or contraction as a result of temperature changes. Casing may fail in service through any one of these causes, acting either singly or in combination. The problem presented in casing design is to estimate the stresses developed under the conditions presented in a particular well, and to select appropriate casing sizes, weights, materials and types to withstand them.

Tensile Stress Developed in a Column of Casing Due to Its Weight, When Suspended from Its Upper End.—If a column of pipe is suspended vertically in a well from its upper end, under static conditions with no frictional contact with the walls of the well, an axial tensional stress will be developed within the pipe by its own dead weight. This stress will range from zero at the lower end to a maximum at the point of support. If the pipe is suspended in air, the maximum stress at the point of support may be computed by the formula

$$S = 12d_s l$$

Here S is the stress in pounds per square inch; d_s is the density of steel in pounds per cubic inch (0.2833); and l is the length of the pipe column in feet.

Ordinarily, the well will be filled with water or drilling fluid and the stress will be reduced by the buoyant effect of the fluid. For this condition, the value of d in the above formula is reduced by the density of the fluid in which the pipe is suspended. Thus, the weight of steel casing in water is 0.2455 lb. per cu. in. or 86.8 per cent of the value in air. In drilling fluid weighing 90 lb. per cu. ft., its weight is 0.230 lb. per cu. in., or 81.1 per cent of its weight in air.

The total tensile load developed by a column of casing suspended in a well filled with drilling fluid is given by the formula

$$L = lw\left(1 - \frac{d_f}{d_s}\right)$$

where L is the load in pounds; l is the length of the column in feet; w is the weight per foot; d_f is the density of the drilling fluid; and d_s is the density of steel.

If the column of casing is closed at its lower end so that the fluid in the well may not enter, a much greater buoyant effect is developed. This may be computed by calculating the weight of the fluid displaced. The total tensile load at the point of support then becomes

$$L = lw - Vd_f$$

where V is the gross volume of the casing within its exterior surfaces.

Strength of Screw Joints in Tension.—The strength of the threaded joint by means of which two lengths of casing are coupled together is ordinarily somewhat less than the tensile strength of the pipe itself. The efficiency of a threaded joint which expresses this relationship is defined as the ratio of tensile strength of the joint to the tensile strength of the pipe at a section where its full wall thickness is not impaired by the cutting of threads. Joint efficiencies for oil-well casings range from 40 to 100 per cent. The latter figure is approached by upsetting the ends of the tubes to maintain full thickness of the pipe wall below the roots of the threads. No threaded joint can be stronger than the area of metal under the root of the first perfect thread. Ordinary A.P.I. joints on pipe not upset seldom exceed a joint efficiency of 70 per cent even for small sizes; for sizes commonly used in casing oil wells, the range is from 50 to 70 per cent, lower in the large sizes.

Under tension, the ordinary type of threaded joint may fail by rupture of the metal at the base of the threads by shearing or stripping of the threads; or by lateral contraction of the pipe and expansion of the coupling. These effects may result in the joint pulling apart under extreme tension. Joint strength becomes especially important in designing long heavy strings of casing to be used in deep wells. The "pull-out" strength of a collared joint is a function of the yield strength of the metal, the length of thread engaged, the thickness of the metal in the engaged threaded portion of the pipe and coupling, and the friction angle of the thread contact relative to the axis of the pipe. Mathematical formulas for computing joint efficiency have been proposed, but results are somewhat uncertain because of difficulty of appraising some of the factors involved. More dependable results are had by physical tests in which full-scale joints are pulled apart under tension. Pull-out strengths of joints are commonly available in tabular or graphic form for standard sizes of A.P.I. casings from tube manufacturers (see Table XXXIV). Where necessary, the joint strength may be calculated with one or the other of the following formulas:

For A.P.I. short couplings:

$$P = C(33.71 - D)\left(\frac{1}{t - 0.07125} + 24.45\right)A$$

For A.P.I. long couplings:

$$P = C(25.58 - D)\left(\frac{1}{t - 0.07125} + 24.45\right) A$$

In these equations, P is the average joint strength in pounds; D is the outside diameter of the casing in inches; d is the inside diameter of the casing in inches; t is the wall thickness of the casing in inches; C is a constant for the grade of steel used; and A is the cross-sectional area in square inches, computed by the expression

$$A = 0.7854[(D - 0.1425)^2 - d^2]$$

Values for C for use in these equations are given in the following table:

Grade of steel	Short couplings	Long couplings
F-25	53.5	
H-40	72.5	
J-55	96.5	159
N-80	112.3	185

Elongation of Casing in Tension.—Occasionally it is necessary to compute the elongation of a suspended column of casing under tension developed by its own weight when hanging freely in the well; or in pulling upward on frozen casing where the pipe is held fast at some point in the well, it may be desired to compute its elongation when a certain lifting force is applied. For such purposes, the following formulas may be used:

$$e = \frac{12PL}{AE} \qquad e = \frac{72dL^2}{E}$$

In these equations, e is the elongation in inches; P is the axial force applied in pounds; L is the length of the casing column in feet; A is the cross-sectional area of metal composing the wall of the pipe; d is the weight per cubic inch (0.2833 lb. for steel); and E is the modulus of elasticity of the material (30,000,000 for steel). The value of d suggested would be appropriate if the pipe column were suspended in air. Usually, however, the well is filled with water or drilling fluid, in which case an appropriate reduction in the value of d must be made, or the following formula may be used:

$$e = \frac{72L^2}{E}[d - 2d_1(1 - u)]$$

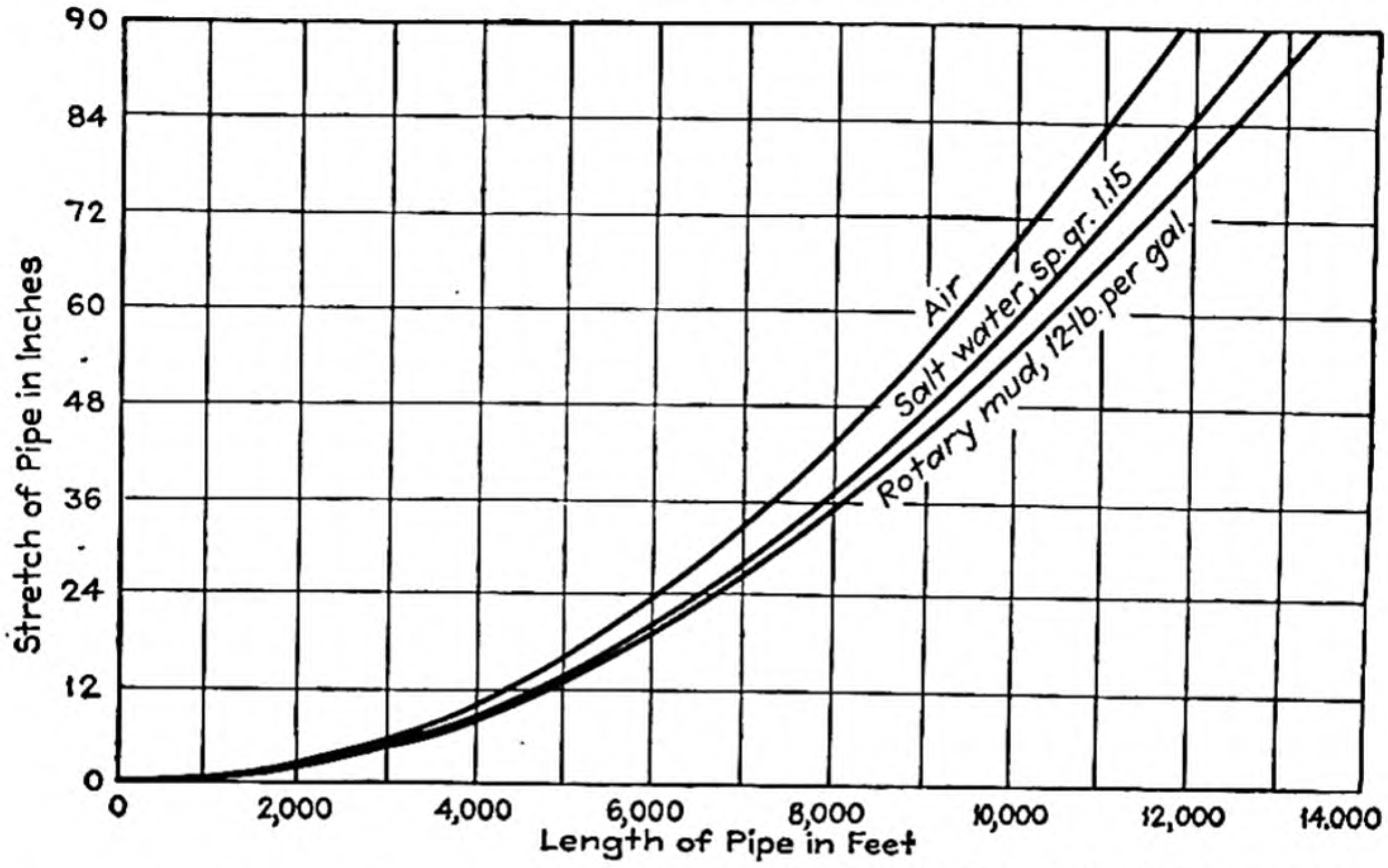
where d_1 is the weight of the fluid in which the pipe is suspended, in lb. per cu. in., (sp. gr. $\times$ 0.03613) and u is Poisson's ratio (for steel, 0.28). The graphs of Fig. 170 indicate the normal elongation of casing columns due to their own weight when suspended in different mediums.

Tensile Stress Developed and Change in Length of Casing Due to Temperature Change.—When a column of casing is subjected to a change in temperature and it is hanging free in the well from a point of suspension at the surface, its length will change, elongation occurring if the temperature is increased, contraction if the temperature is lowered. Such change in temperature may occur as a result of expansion of flowing gas, or circulation of cool fluids from the surface or hot fluids from deep-seated formations. The change in length of the column may be computed with the aid of the following equation:

$$e = 12Lat$$

Here e is the change in length in inches (increase if temperature is increased, contraction if temperature is reduced); L is the length of the pipe before the change in temperature occurs; a is the coefficient of expansion (0.0000069 for steel); and t is the temperature change in degrees Fahrenheit. A temperature change of 100°F. produces a change in length of a column of casing of 0.78 in. per 100 ft.

Development of axial tensional stress in a column of casing as a result of temperature change is realized only when the ends of the pipe column are fixed so that compensating changes in length may not occur. Tendency to contract as a result



(*From Spang, Chalfant & Co.'s data sheets.*)

FIG. 170.—Elongation of steel casing, tubing or drill pipe under the influence of its own weight while suspended freely in various fluid media.

of reduction in temperature will then be resolved into tensional stress, but compressive strain developed by expansion will generally be relieved by bending or distortion of the column. If the ends of the pipe are fixed so that contraction in length may not occur, the resulting stress developed in the pipe may be computed with the aid of the formula

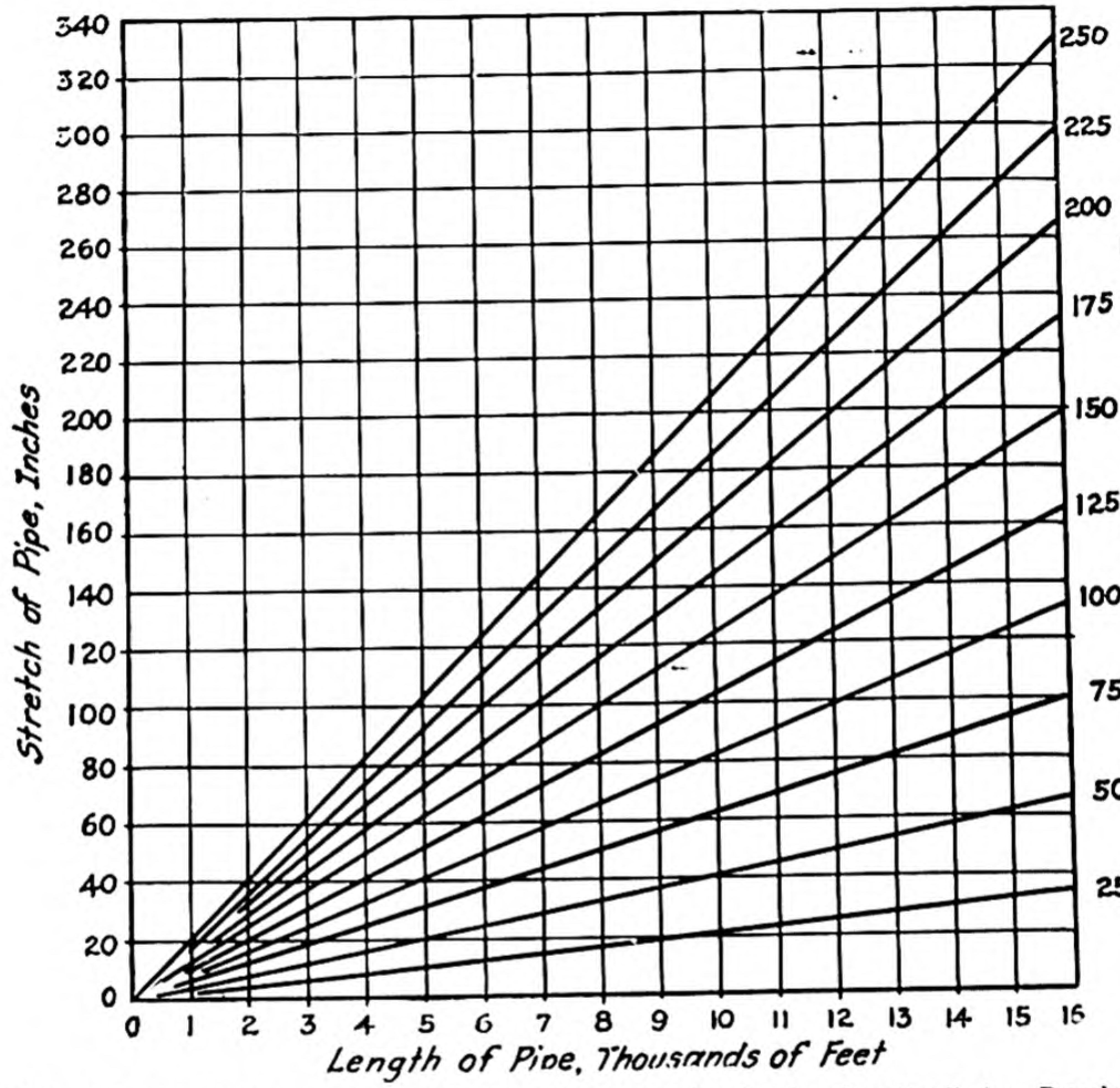
$$S = atE$$

In this expression, S is the casing stress in pounds per square inch; a is the coefficient of expansion of the material; t is the temperature change in degrees Fahrenheit; and E is the modulus of elasticity of the material. Computation indicates a value for S for steel, of 195 lb. per sq. in. per deg. F.

Figure 171 indicates graphically the effect of temperature change in influencing linear expansion or contraction of steel pipe and stress developed as a result thereof, in a column of casing in which the ends are anchored.

Collapse of Casing.—Collapse of casing may occur as a result of application of external pressure having its origin in hydrostatic head brought to bear on the pipe by sealing the lower end; or of earth pressure developed by caving or shifting walls or sudden heaving of unconsolidated sand or shale into the well from gas-bearing horizons. Where casing is set to exclude "top" water, fluid accumulating in the annular space outside the pipe may reach elevations many hundreds of feet above the casing shoe, at times even to the surface. The hydrostatic head so developed, tending

to collapse the casing, will vary with the density of the fluid. Thus, pure water develops a pressure of 0.433 lb. per ft. of depth; saline ground water, containing 33,800 parts of dissolved salt per million, develops a pressure of 0.444 lb. per ft.; drilling fluid weighing 10 lb. per gal., 0.520 lb. per ft.; and 15-lb. drilling fluid, 0.780 lb. per ft. For average conditions, in making approximate computations, we may assume that the fluid has a density of 1.15 and that it develops a static pressure of 0.5 lb. per sq. in. per ft. of depth. In conservative computations it is well to assume that fluid outside the pipe may rise to the surface and that a collapsing pressure will be developed on the casing equivalent to a fluid head of its full length. Reflection will



(*After Wescott, Dunlop and Kemler in "Drilling and Production Practice," Am. Petroleum Inst., 1940.*)

FIG. 171.—Effect of temperature change on linear expansion of steel pipe.

show that this collapsing pressure may become a force of great magnitude, reaching, for example, as much as 5,000 lb. per sq. in. in a well 10,000 ft. deep.

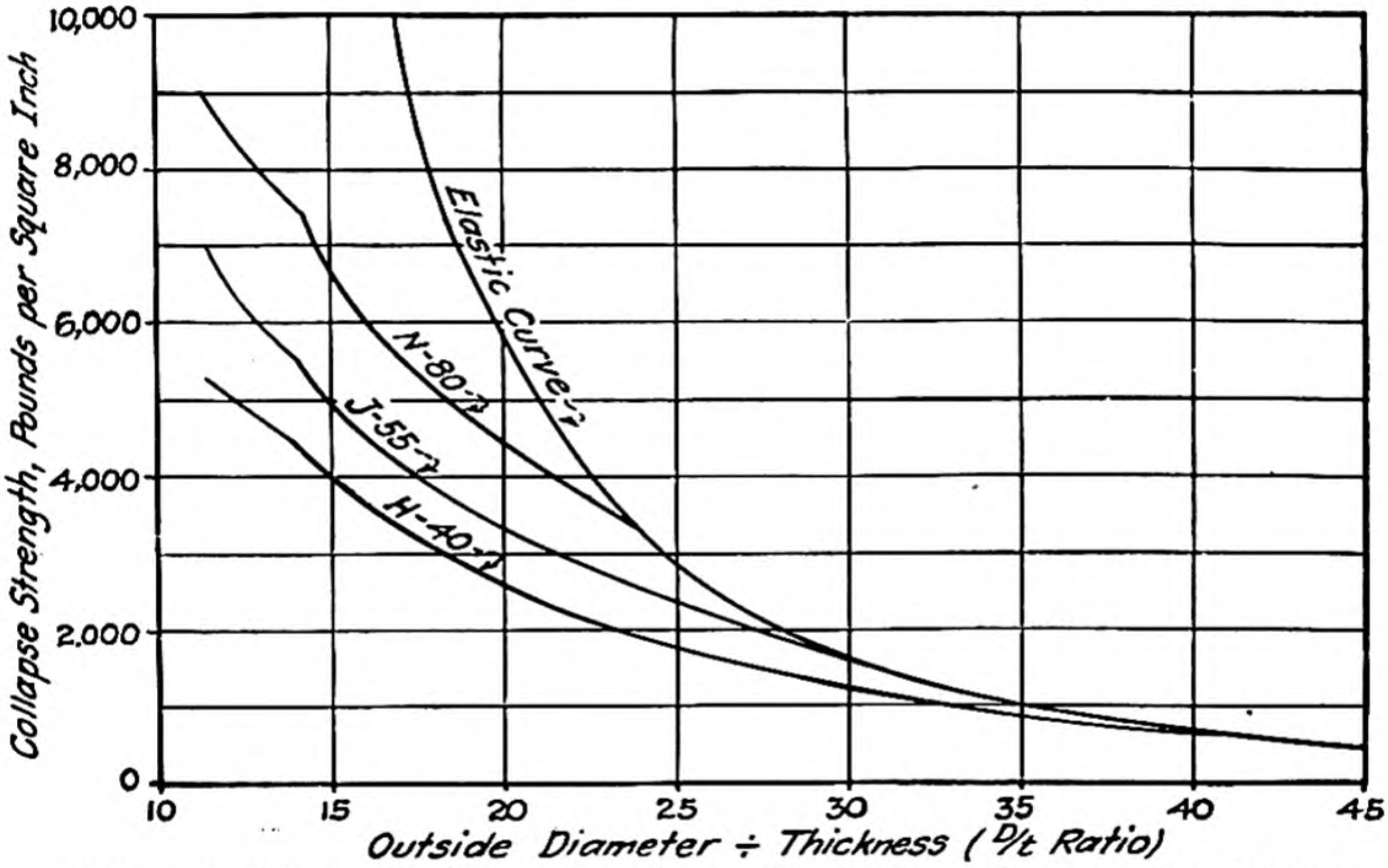
When a tube resists uniform external pressure, the metal is subjected to compressive strain. Up to a certain point, as pressure is increased under equilibrium conditions, it will contract uniformly like any elastic body. Above a critical pressure, the tube becomes unstable and "plastic failure" ultimately results by buckling of the walls. This is a condition somewhat analogous to the buckling of columns and is influenced by the load imposed and a factor called the "slenderness ratio," which is expressed by the ratio of the external diameter of the tube divided by the wall thickness (D/t). For thin-walled tubes where the value of the ratio of outside diameter of the tube to its wall thickness exceeds 14, the unit stress developed is apparently not a determining factor, nor is the type or quality of the material except insofar as these

qualities influence the modulus of elasticity. For relatively thick-walled tubes, where the value of the ratio of D/t is smaller than 14, the elastic properties of the metal are of less consequence, and resistance offered to collapse depends upon the yield strength of the material.

The resistance offered by tubes to external pressure tending to cause collapse has been the subject of many investigations and out of them have evolved a variety of formulas that are used in making computations of this character. An equation expressing the relationship of variables in elastic collapse is the following:

$$P = \left[\frac{2E}{1 - r^2}\right]\left[\frac{1}{(D/t)(D/t - 1)^2}\right]$$

Here P is the collapsing pressure in pounds per square inch; D is the outside diameter of the pipe in inches; t is the thickness of the wall of the pipe in inches; E is Young's



(*After J. O. Hills in "Drilling and Production Practice," Am. Petroleum Inst., 1939.*)

FIG. 172.—Minimum collapse strength of standard A.P.I. casings.

modulus of elasticity; and r is Poisson's ratio. A curve derived from this equation (see Fig. 172) has been found to be an upper boundary for numerous physical tests of collapsing pressure that have been made on specimens of A.P.I. casings of grades H-40, J-55 and N-80 steel. By assuming a value of 30,000,000 for Young's modulus and 0.3 for Poisson's ratio, the above equation may be simplified as follows:

$$P = \frac{62.6 \times 10^6}{(D/t)(D/t - 1)^2}$$

This equation is suitable for application in all cases where failure is elastic.

Where the value of D/t exceeds 14 but is less than that at which failure will occur as indicated by the elastic curve (see Fig. 172), the collapsing pressure may be computed with the aid of the following formula:

$$P = S\left(\frac{2.503}{D/t} - 0.0460\right)$$

TABLE XXXIV.—SETTING-DEPTH PROPERTIES OF A.P.I. STANDARD CASINGS*

O.D. of casing, in.	4½			5				5½						6			
O.D. of coupling, in.	5.000			5.563				6.050						6.625			
Nominal weight, lb. per ft., threads and coupling	9.50	11.60	13.50	11.50	13.00	15.00	18.00	13.00	14.00	15.50	17.00	20.00	23.00	15.00	18.00	20.00	23.00
I.D., in.	4.090	4.000	3.920	4.560	4.494	4.408	4.276	5.044	5.012	4.950	4.892	4.778	4.670	5.524	5.424	5.352	5.240
Wall thickness, in.	.205	.520	.290	.220	.253	.296	.362	.228	.244	.275	.304	.361	.415	.238	.288	.324	.380
Drift diameter, in.	3.965	3.875	3.795	4.435	4.369	4.283	4.151	4.919	4.887	4.825	4.767	4.653	4.545	5.399	5.299	5.227	5.115
Collapse resistance, lb. per sq. in.:																	
Grade F-25	1,920			1,820				1,660						1,540			
Grade H-40	2,550								2,440						2,780		
Grade J-55	3,320	4,540		3,130	3,930	4,980			3,170	3,860	4,500				3,620		
Grade N-80		5,930	7,350			6,520	8,550				5,890	7,580	8,900		4,730	5,690	7,180
Internal yield pressure, lb. per sq. in.:																	
Grade F-25	1,990			1,930				1,810						1,740			
Grade H-40	3,190								3,110						3,360		
Grade J-55	4,380	5,350		4,240	4,870	5,700			4,270	4,810	5,320				4,620		
Grade N-80		7,780	9,020			8,290	10,140				7,740	9,190	10,560		6,720	7,560	8,870
Joint strength, 1,000 lb:																	
Short threads																	
Grade F-25	71			84				95						108			
Grade H-40	96								139						179		
Grade J-55	128	159		152	178	210			186	211	234				239		
Grade N-80		185	217			244	300				273	326	375		278	314	371
Long threads																	
Grade J-55		189			210	247				247	275				278		
Grade N-80		220	258			288	354				320	382	440		323	366	432
Joint strength, ft.:																	
Short threads																	
Grade F-25	7,470			7,300				7,310						7,200			
Grade H-40	10,110								9,930						9,940		
Grade J-55	13,470	13,710		13,220	13,690	14,000			13,290	13,610	13,760				13,280		
Grade N-80		15,950	16,070			16,270	16,670				16,060	16,300	16,300		15,440	15,700	16,130
Long threads																	
Grade J-55		16,290			16,150	16,470				15,940	16,180				15,440		
Grade N-80		18,970	19,110			19,200	19,670				18,820	19,100	19,130		17,940	18,300	18,780

TABLE XXXIV.—SETTING-DEPTH PROPERTIES OF A.P.I. STANDARD CASINGS.*—(*Continued*)

O.D. of casing, in.	6⅝					7							
O.D. of coupling, in.	7.390					7.656							
Nominal weight, lb. per ft., threads and coupling	17.00	20.00	24.00	28.00	32.00	17.00	20.00	23.00	26.00	29.00	32.00	35.00	38.00
I.D., in.	6.135	6.049	5.921	5.791	5.675	6.538	6.456	6.366	6.276	6.184	6.094	6.004	5.920
Wall thickness, in.	.245	.288	.352	.417	.475	.231	.272	.317	.362	.408	.453	.498	.540
Drift diameter, in.	6.010	5.924	5.796	5.666	5.550	6.413	6.331	6.241	6.151	6.059	5.969	5.879	5.795
Collapse resistance, lb. per sq. in.:													
Grade F-25	1,370	...	...	...	...	1,100							
Grade H-40	...	2,360	...	...	...	1,370	1,920						
Grade J-55	...	3,060	4,250	...	...	...	2,500	3,290					
Grade N-80	...	...	5,550	7,110	8,490	...	...	4,300	5,320	6,370	7,400	8,420	9,080
Internal yield pressure, lb. per sq. in.:													
Grade F-25	1,620	...	...	...	...	1,440							
Grade H-40	...	3,040	...	...	...	2,310	2,720						
Grade J-55	...	4,180	5,110	...	...	...	3,740	4,360					
Grade N-80	...	...	7,440	8,810	10,040	...	...	6,340	7,240	8,160	9,060	9,960	10,800
Joint strength, 1,000 lb.:													
Short threads													
Grade F-25	121	...	...	...	...	118							
Grade H-40	...	195	...	...	...	160	191						
Grade J-55	...	259	320	...	...	...	254	300					
Grade N-80	...	...	373	443	506	...	...	350	402	454	505	554	600
Long threads													
Grade J-55	...	293	370	...	...	...	...	344					
Grade N-80	...	...	430	511	582	...	...	400	460	520	578	635	688
Joint strength, ft.:													
Short threads													
Grade F-25	7,120	...	...	...	...	6,940							
Grade H-40	...	9,750	...	...	...	9,410	9,550						
Grade J-55	...	12,950	13,330	...	...	...	12,700	13,040					
Grade N-80	...	...	15,540	15,820	15,810	...	...	15,220	15,460	15,660	15,780	15,830	15,790
Long threads													
Grade J-55	...	14,650	15,420	...	...	...	...	14,960					
Grade N-80	...	...	17,920	18,250	18,190	...	...	17,390	17,690	17,930	18,060	18,140	18,110

* Courtesy of American Petroleum Institute.

TABLE XXXIV.—SETTING-DEPTH PROPERTIES OF A.P.I. STANDARD CASINGS.*—(*Continued*)

O.D. of casing, in.	7⅝						8⅝							9⅝						
O.D. of coupling, in.	8.500						9.625							10.625						
Nominal weight, lb. per ft., threads and coupling	20.00	24.00	26.40	29.70	33.70	39.00	24.00	28.00	32.00	36.00	40.00	44.00	49.00	29.30	32.30	36.00	40.00	43.50	47.00	53.50
I.D., in.	7.125	7.025	6.969	6.875	6.765	6.625	8.097	8.017	7.921	7.825	7.725	7.625	7.511	9.063	9.001	8.921	8.835	8.755	8.681	8.535
Wall thickness, in.	.250	.300	.328	.375	.430	.500	.264	.304	.352	.400	.450	.500	.557	.281	.312	.352	.395	.435	.472	.545
Drift diameter, in.	7.000	6.900	6.844	6.750	6.640	6.500	7.972	7.892	7.796	7.700	7.600	7.500	7.386	8.907	8.84	8.765	8.679	8.599	8.525	8.379
Collapse resistance, lb. per sq. in.:																				
Grade F-25	1,100	.....	.....	.....	.....	.....	950			.....	.....	.....	.....	860						
Grade H-40	.....	1,970	.....	.....	.....	.....	.....	1,580	2,110	.....	.....	.....	.....	.....	1,320	1,710				
Grade J-55	.....	.....	3,010	.....	.....	.....	.....	.....	2,740	3,420	.....	.....	.....	.....	.....	2,220	2,770			
Grade N-80	.....	.....	3,930	4,910	6,070	7,530	.....	.....	.....	4,470	5,390	6,320	7,370	.....	.....	.....	3,530	4,280	4,900	6,110
Internal yield pressure, lb. per sq. in.:																				
Grade F-25	1,430		.....	.....	.....	.....	1,340			.....	.....	.....	.....	1,280						
Grade H-40	.....	2,750	.....	.....	.....	.....	.....	2,470	2,860	.....	.....	.....	.....	.....	2,270	2,560				
Grade J-55	.....	.....	4,140	.....	.....	.....	.....	.....	3,930	4,460	.....	.....	.....	.....	.....	3,520	3,950			
Grade N-80	.....	.....	6,020	6,890	7,890	9,180	.....	.....	.....	6,490	7,300	8,120	9,040	.....	.....	.....	5,750	6,330	6,870	7,930
Joint strength, 1,000 lb.:																				
Short threads																				
Grade F-25	138	.....	.....	.....	.....	.....	161	.....	.....	.....	.....	.....	.....	185						
Grade H-40	.....	227	.....	.....	.....	.....	.....	252	295	.....	.....	.....	.....	.....	279	318				
Grade J-55	.....	.....	333	.....	.....	.....	.....	.....	393	448	.....	.....	.....	.....	.....	422	477			
Grade N-80	.....	.....	387	446	513	596	.....	.....	.....	522	589	654	729	.....	.....	.....	555	614	666	770
Long threads																				
Grade J-55	.....	.....	378	.....	.....	.....	.....	.....	437	499	.....	.....	.....	.....	.....	462	521			
Grade N-80	.....	.....	439	505	581	676	.....	.....	.....	581	655	729	812	.....	.....	.....	606	670	727	841
Joint strength, ft.:																				
Short threads																				
Grade F-25	6,900		.....	.....	.....	.....	6,710			.....	.....	.....	.....	6,310						
Grade H-40	.....	9,460	.....	.....	.....	.....	.....	9,000	9,200	.....	.....	.....	.....	.....	8,640	8,830				
Grade J-55	.....	.....	12,610	.....	.....	.....	.....	.....	12,280	12,440	.....	.....	.....	.....	.....	11,720	11,920			
Grade N-80	.....	.....	14,660	15,020	15,220	15,280	.....	.....	.....	14,500	14,720	14,860	14,880	.....	.....	.....	13,880	14,110	14,170	14,390
Long threads																				
Grade J-55	.....	.....	14,320	.....	.....	.....	.....	.....	13,660	13,860	.....	.....	.....	.....	.....	12,830	13,020			
Grade N-80	.....	.....	16,630	17,000	17,240	17,330	.....	.....	.....	16,140	16,380	16,570	16,570	.....	.....	.....	15,150	15,400	15,470	15,720

TABLE XXXIV.—SETTING-DEPTH PROPERTIES OF A.P.I. STANDARD CASINGS.*—(*Continued*)

O.D. of casing, in.	10¾					11¾					13⅜					16				20
O.D. of coupling, in.	11.750					12.750					14.375					17.000				21.000
Nominal weight, lb. per ft., threads and coupling	32.75	40.50	45.50	51.00	55.50	38.00	42.00	47.00	54.00	60.00	48.00	54.50	61.00	68.00	72.00	55.00	65.00	75.00	84.00	90.00
I.D., in.	10.192	10.050	9.950	9.850	9.760	11.150	11.084	11.000	10.880	10.772	12.715	12.615	12.515	12.415	12.347	15.375	15.250	15.125	15.010	19.166
Wall thickness, in.	.279	.350	.400	.450	.495	.300	.333	.375	.435	.489	.330	.380	.430	.480	.514	.3125	.375	.4375	.495	.417
Drift diameter, in.	10.036	9.894	9.794	9.694	9.604	10.994	10.928	10.884	10.724	10.616	12.559	12.459	12.359	12.259	12.191	15.187	15.062	14.937	14.822	18.978
Collapse resistance, lb. per sq. in.:																				
Grade F-25	650					620					560					280				340
Grade H-40	710	1,340					940				740						640			440
Grade J-55		1,730	2,300	2,870				1,630	2,270	2,840		1,140	1,670	2,140				1,010	1,480	
Grade N-80				3,750	4,420					3,710					2,880					
Internal yield pressure, lb. per sq. in.:																				
Grade F-25	1,140					1,120					1,080					850				910
Grade H-40	1,820	2,280					1,980				1,730						1,640			1,460
Grade J-55		3,130	3,580	4,030				3,070	3,560	4,010		2,730	3,090	3,450				2,630	2,980	
Grade N-80				5,860	6,450					5,830					5,380					
Joint strength, 1,000 lb.:																				
Short threads																				
Grade F-25	196					222					260					258				341
Grade H-40	265	338					336				352						423			461
Grade J-55		450	518	585				507	593	668		545	613	695				662	753	
Grade N-80				680	750					778					868					
Long threads																				
Grade J-55		478	550	622				526	614	694		545	614	695						
Grade N-80				724	798					807					868					
Joint strength, ft.:																				
Short threads																				
Grade F-25	5,980					5,840					5,420					4,690				3,790
Grade H-40	8,090	8,350					8,000				7,330						6,510			5,120
Grade J-55		11,100	11,380	11,470				10,790	10,980	11,130		10,000	10,050	10,220				8,830	8,860	
Grade N-80				13,330	13,510					12,970					12,060					
Long threads																				
Grade J-55		11,800	12,090	12,200				11,190	11,370	11,570		10,000	10,070	10,220						
Grade N-80				14,200	14,380					13,450					12,060					

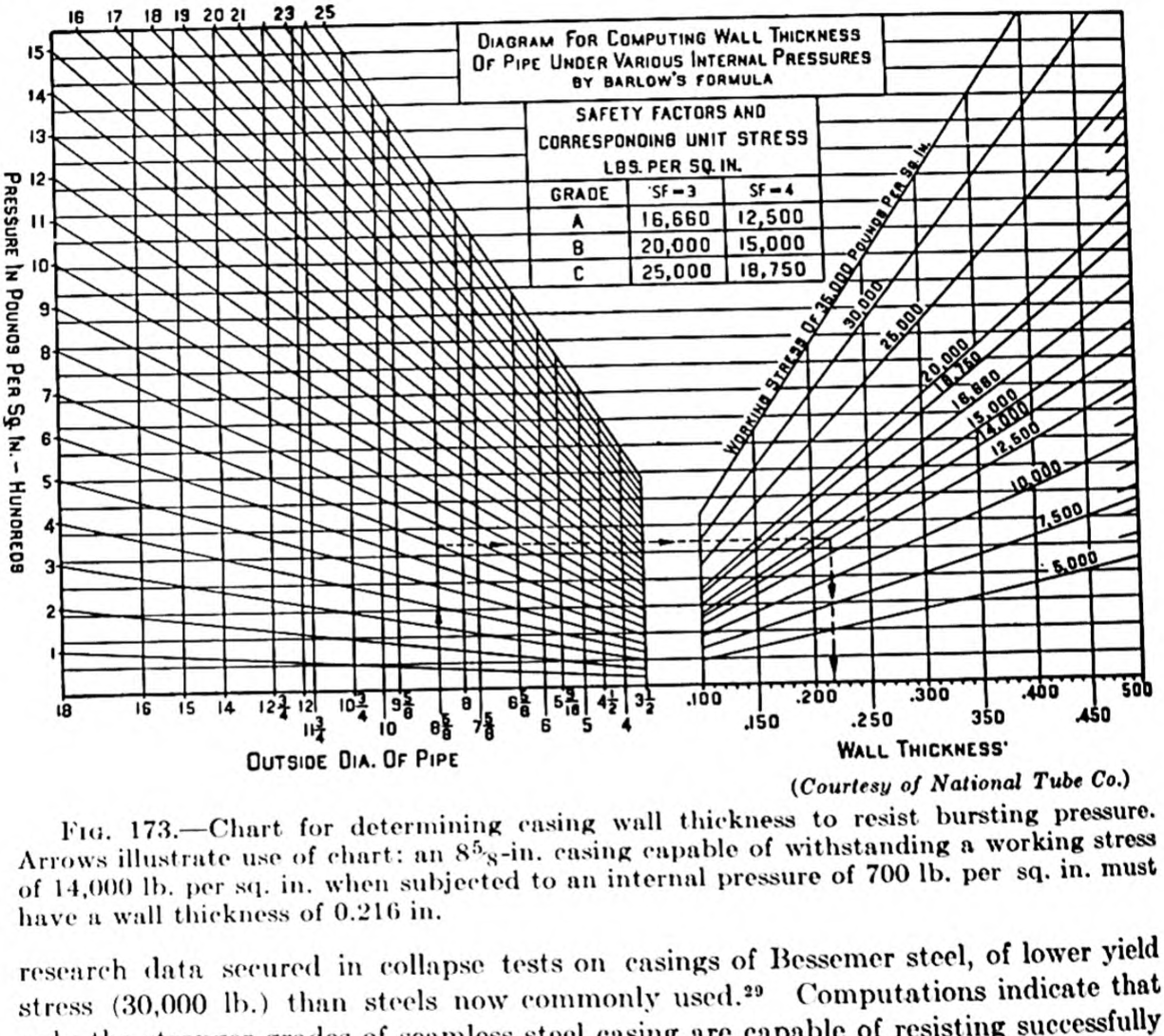
* Courtesy of American Petroleum Institute.

where S is the average longitudinal tensile yield strength of the material in pounds per square inch and P, D and t are as previously defined.

For thick-walled tubes, where the value of D/t is less than 14,

$$P = \frac{2s(D/t - 1)}{(D/t)^2}$$

Data on collapse resistance of well casings are available in "setting-depth" tables prepared by the tube manufacturers, often assuming a certain safety factor. Table XXXIV presents minimum setting depths for A.P.I. standard casings based on collapse resistances computed with the aid of the formulas given above.[12] For many years, such tables were based on Stewart's formulas, which were developed from



(*Courtesy of National Tube Co.*)

FIG. 173.—Chart for determining casing wall thickness to resist bursting pressure. Arrows illustrate use of chart: an $8\frac{5}{8}$-in. casing capable of withstanding a working stress of 14,000 lb. per sq. in. when subjected to an internal pressure of 700 lb. per sq. in. must have a wall thickness of 0.216 in.

research data secured in collapse tests on casings of Bessemer steel, of lower yield stress (30,000 lb.) than steels now commonly used.[29] Computations indicate that only the stronger grades of seamless steel casing are capable of resisting successfully the hydrostatic heads developed in the deeper wells recently drilled in American fields. For example, $8\frac{5}{8}$-in.-36-lb. casing of J-55 steel will be in danger of collapse if cemented at a depth of 3,420 ft. Seamless grade N-80 casing of the same size and weight has a minimum safe setting depth of 4,470 ft., and, by increasing the weight to 49 lb. per ft., the safe setting depth may be increased to 7,370 ft.[33]

Bursting Stress Due to Internal Pressure in Casing.—Casing columns are occasionally subjected to high internal pressure, creating stress tending to cause failure of the pipe by bursting. This may occur when fluids are forced into the casing under high pump pressure, as in "squeeze cementing," or when a column of casing, sealed about its lower end by a packer or cement plug, carries high-pressure gas. Shut-in pressures

of several thousand pounds per square inch are possible under such circumstances.

When a tube is subjected to internal pressure, the forces operative tend to hold it in cylindrical form and are resolved into tensional stress around the circumference of the tube at right angles to the axis. If a safe working stress is exceeded, the pipe fails by splitting longitudinally. Barlow's formula, which may be used for computing this stress due to internal pressure, is as follows:

$$P = \frac{2St}{D}$$

Here P is the bursting pressure in pounds per square inch; S is the permissible stress in the steel, in pounds per square inch; t is the thickness of the wall of the tube and D is its outside diameter in inches. Conservative practice would assume a permissible stress no greater than the yield point of the metal and some would prefer a value of perhaps a half or a third of the ultimate tensile strength. One should bear in mind that permissible variations in tube manufacture allow the wall thickness of casing to be as much as 12½ per cent less than the standard or nominal thickness. Figure 173 presents a chart by means of which the necessary wall thickness of casing may be determined for any given values of internal pressure, diameter and safe working stress.[8]

Strength of Casing in Column Loading.—When casing is set on bottom and is not supported or is only partly supported at the upper end, there is possibility of failure by buckling under excessive column loading. Under such circumstances, if caving or erosion of the walls of the well has left a cavity about the pipe so that it does not receive support from the walls, it must function as a column in supporting the weight of the pipe above. The column strength of casing increases rapidly with increase in diameter and, for a given diameter, is approximately proportional to the weight. The following formula permits of calculating the load at which failure will occur by column action:

$$P = \frac{\pi^2 EI}{L}$$

Here P is the load in pounds, at which buckling will occur; E is the modulus of elasticity of the material (30,000,000 for steel); L is the length of the unsupported pipe in inches; and I is the moment for inertia of the section. For a tube, $I = \frac{\pi}{64}(D^4 - d^4)$, where D is the external diameter, and d the internal diameter in inches.

Computations will indicate that buckling under column action is a likely cause of failure if even a hundred feet or so of casing are allowed to rest on bottom without wall support. Thus, if a column of 7-in. 26-lb. casing rests on bottom and 200 ft. of it are without wall support, a superimposed load of only 2,100 lb. will cause buckling. This is equivalent to only 81 ft. of this weight of casing. The graphs of Fig. 174 indicate column strengths of sizes of pipe commonly used as liners in oil wells.[13]

Columns of casing extending to the surface are commonly supported from their upper ends, so that they are maintained under tension, and buckling due to column action may not occur. But where this practice is not followed or where insufficient tension is taken at the casing head to support the full weight of the column, failure may occur wherever the walls of the well fail to give adequate support. Liners which do not extend to the surface, and which are sometimes allowed to rest on bottom while cavities form about them by disintegration of the producing formation, are frequently distorted by column action. This difficulty may be avoided by use of a liner hanger which supports the pipe from its upper end on "slips" which engage the inner wall of the surrounding casing (see Fig. 246).

Bending Stress in Casing.—Bending stress sufficient to cause distortion of casing may result in either of two ways. In a crooked hole, the casing must adapt itself to changes in the direction of the well; and where conditions develop which cause caving or bulging of the wall of the well against the pipe, lateral stresses of considerable magnitude may result. Though difficult to evaluate on any mathematical basis, these stresses are probably often responsible for deformation of casing columns, especially where the wells penetrate high-pressure unconsolidated formations. Where a well has been surveyed and the deviation and direction of the axis from the vertical are

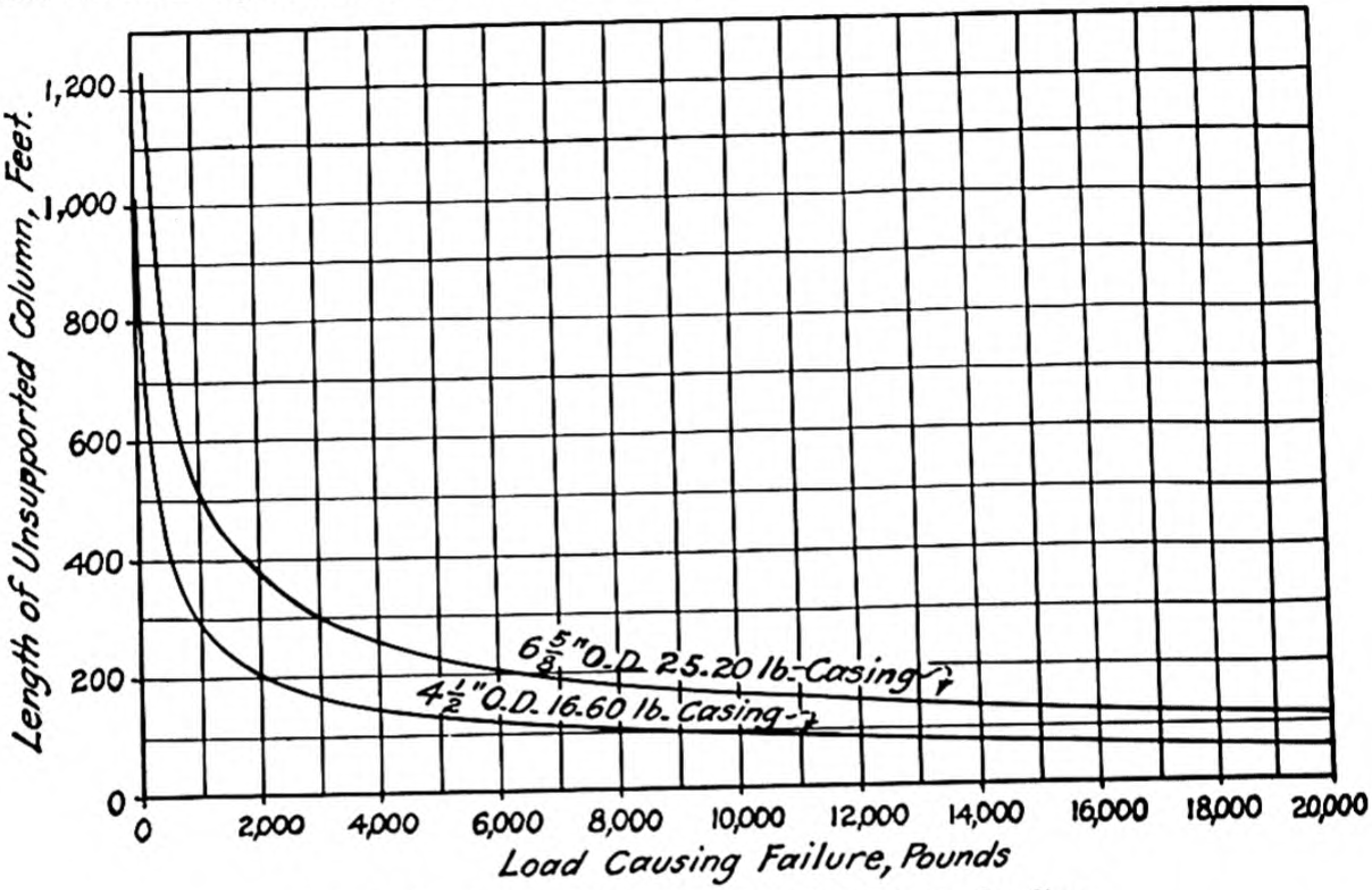


FIG. 174.—Strength of casing under column loading.

known, it is possible to estimate the bending stress developed during insertion into the well, with the aid of the formula:

$$S = \frac{CE}{12R}$$

In this formula, S is the unit stress developed, in pounds per square inch; C is one-half of the outside diameter of the pipe, in inches; E is the modulus of elasticity of the material (30,000,000 for steel); and R is the radius of curvature. If, as is usual, the survey data give deflection from the vertical in degrees, instead of the radius of curvature, we may compute the latter by substituting in the formula:

$$a = \frac{5{,}720}{R}$$

in which a is the angle from the vertical in degrees, and R is the radius of curvature in feet.[13]

With large-diameter casing, the stress developed by running casing into a crooked hole may become an important contributing factor in casing failure. For example, if casing $8\frac{5}{8}$ in. in diameter is run into a hole in which there is a 5.3-deg. change in direction in 100 ft. of hole, the stress developed in the pipe will be 10,000 lb. per sq. in., and if the deflection were 16 deg. in 100 ft., the bending stress would be 30,000 lb. per sq. in. Failure of casing columns under bending loads will generally occur by pulling-

out of the threaded joints in the couplings, threaded joints being incapable of withstanding severe deflection. Tests on A.P.I. joints indicate that failure of the joint usually occurs at a load slightly less than the yield point of the pipe.

Combined Stresses in Well-casing Installations.—It is apparent that in many casing installations two or more of the different types of stresses described in the foregoing sections may be simultaneously operative. For example, a column of casing may be subjected to tensional stress resulting from its own weight while suspended from the casing head, and collapsing pressure due to hydrostatic pressure in the annular space about it. Or longitudinal tensional stress may be combined with tensional stresses due to internal bursting pressure or contraction as a result of temperature change. Unfortunately, these stresses are often cumulative and may add up to a combined stress exceeding the yield point of the metal, though inspection of any single stress might indicate a safe condition.

Inasmuch as tensional stress and collapsing stress are both large and mutually influenced, particular attention should be given to their combined effect. In a casing string composed entirely of one size, weight and grade of pipe, the maximum collapsing pressure is developed at the lower end and the maximum tensile stress or "pull-out" stress at the upper end. The combined stress will never be greater than that developed by the collapsing pressure at the lower end, unless contraction due to temperature change is also simultaneously operative or a lifting force in excess of the weight of the string is applied at the surface. However, when a graduated string is used, made up of two or more different weights or grades or sizes of pipe, it is possible that combined stresses due to tensional and collapsing forces may be less than the yield point of the metal at the top and bottom of the string, but in excess at some intermediate point. Another situation that may arise is the case where high-pressure gas is excluded from the casing by a cement plug about its lower end, but is free to rise in the annular space about it to the casing head. Here we will have a combination of high collapsing force due to gas pressure, and maximum tensile stress due to weight of the string, simultaneously operative at the upper end of the string.

Where both longitudinal tensile stress and external collapsing stress are applied to a tube, failure may occur below the normal yield point of the metal. Conversely, application of longitudinal compressive stress, achieved by partial release of supporting tension at the surface, will enable the pipe to withstand a higher collapsing pressure without failure. Calculation of the resultant of component stresses is difficult, but the following theoretical equation may be used for an approximation:

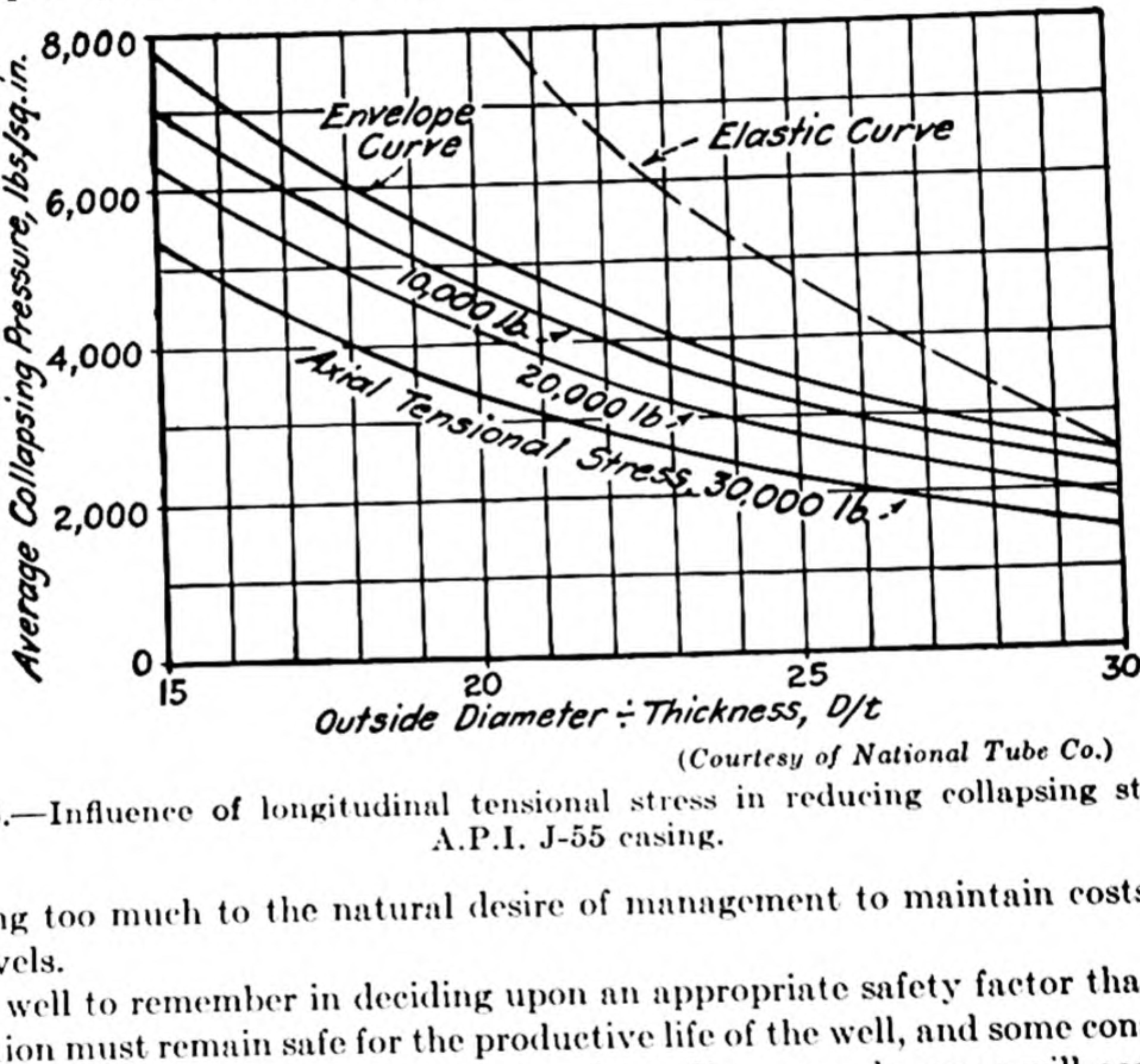
$$S^2 = S_c^2 + S_t^2 + 2uS_tS_c$$

Here S is the yield stress; S_c is the collapsing stress; S_t is the tensional or longitudinal stress; and u is Poisson's ratio (0.26 for steel). The graphs of Fig. 175 illustrate, for a commonly used A.P.I. grade of steel, the extent to which the collapsing strength is diminished by combined longitudinal tensional stress.[16]

Safety Factors in Casing Design.—In earlier years, setting-depth tables for casing were usually computed on the assumption that one-half the average yield strength of the metal should not be exceeded; that is, a safety factor of 2, based on the average yield strength, was assumed. More recently, it has been considered better practice to use a safety factor based on the minimum yield strength of the material; and since use of the minimum value in itself eliminates the necessity for any allowance for variation in the quality of the material, a lower safety factor may be employed than when average values are used. On this basis, some engineers have felt justified in using a safety factor as low as 1.25 in fixing the safe collapsing stress. Calculations based on allowable longitudinal tensional stress and joint strength probably require

a safety factor of at least 1.8, preferably 2, because of the possibility of shock loads and generally somewhat uncertain joint efficiency. The minimum yield strength in collapse computations is assumed to be 75 per cent of the average yield point of the metal; for joint strength, 85 per cent of the average; and for bursting stress, 87½ per cent of the average.[23,33]

Apart from unavoidable minor variations in the quality of the material, one of the principal reasons for using a high safety factor is the uncertainty in estimating the forces that may be brought to bear when the casing is in the well and during the process of insertion. If the stresses imposed could be determined precisely, lower safety factors might be used. In casing very deep wells, one must be content with the minimum safety factor that prudent engineering practice will countenance; otherwise weights greater than provided by A.P.I. standards must be specified and the cost becomes excessive. Yet, insecurity in a casing installation may ultimately involve greater expense, and in setting safety factors the engineer must be careful to avoid



(*Courtesy of National Tube Co.*)

FIG. 175.—Influence of longitudinal tensional stress in reducing collapsing strength of A.P.I. J-55 casing.

conceding too much to the natural desire of management to maintain costs at minimum levels.

It is well to remember in deciding upon an appropriate safety factor that a casing installation must remain safe for the productive life of the well, and some consideration should be given to its deterioration in service. For example, wear will occur on the inside surface of a water string, tending to reduce wall thickness and joint security, as a result of frictional contact with the rotating drill pipe; and corrosion that will perhaps be cumulative over a period of years, both on the inside and outside surfaces, will reduce the thickness of metal opposing collapse and available for supporting longitudinal tensional loads. Where available standard casing sizes and economic considerations permit, it would appear to be a desirable policy, in selecting a safety factor, to consider the lifetime requirements likely to be imposed and make appropriate allowance for deterioration in service.

Procedure in Design of Casing Installations.—Design of a casing installation involves consideration of many factors, some physical in character, some economic. The problem presented is that of assuring

the security of the well and its equipment at the lowest possible cost, and establishing conditions that will permit of most efficient production. The subsurface conditions must be appraised carefully. What depth must be reached? How many changes in casing size will be required? What fluid pressures will be encountered and in what formational intervals? Are the fluids highly corrosive? What is the nature of the formations to be penetrated by the well, and at what depths are competent strata to be found in which casing strings can be "landed" and water shutoffs made? What is the maximum rate of production that the well is likely to attain, and what lifting method will be employed? Is the well to be cased so that it may produce from a single producing zone or from two or more zones simultaneously? Is it probable that the well will be deepened or "plugged back" at some future time to produce from some other horizon than that in which it is first completed? The casing design will be dictated in many cases by economic considerations and administrative policy. Preservation of a large-diameter bore through the reservoir rock promotes recovery efficiency, but large-diameter casings are expensive and a slim-hole program will usually result in lower well-completion cost. Under commonly applied production restrictions, the smaller diameter well, though less efficient from the standpoint of operating efficiency, may yet permit of taking production as rapidly as proration authorities will permit. The exploitation procedure adopted for the field will often require a certain casing program; that is, water shutoffs will be uniformly made in a certain stratigraphic horizon. A certain penetration of the producing formation will be the objective; casings penetrating certain producing zones will be perforated for production while others perhaps will be reserved for future production and cased off. Always, production cost will be a controlling consideration, and inasmuch as casing cost represents a large percentage of development cost, the engineer will ever be alert to discover ways of reducing casing cost without introducing undesirable hazards or unduly restricting production efficiency.

Design of Oil Strings and Liners.—Having determined the number of strings of casing and the length and purpose of each string to be installed in a given well and the conditions to which it will be subjected, the first consideration in selecting the grades, sizes and weights of pipe to be used will be that of determining whether an oil string or liner will be used through the producing interval, and what its diameter will be. These decisions will depend on the character of the reservoir rock, the probable productive capacity of the well, the physical properties of the oil, the formation pressure, the gas-oil ratio and the method to be employed in lifting the oil to the surface. Unconsolidated or semi-consolidated reservoir rocks, high rates of production, highly viscous

oils and high gas-oil ratios will usually require larger diameter oil strings than where other conditions exist. Though a well may initially be operated by natural flow or gas-lift methods, it must generally be assumed that it will eventually be mechanically pumped; hence, the oil string or liner must be large enough to accomodate a pump of suitable capacity to handle the well's production. There must be, in addition, a moderate amount of space about the pump and well tubing in which gas may separate and oil accumulate, and in which fishing tools may be operated if necessary.

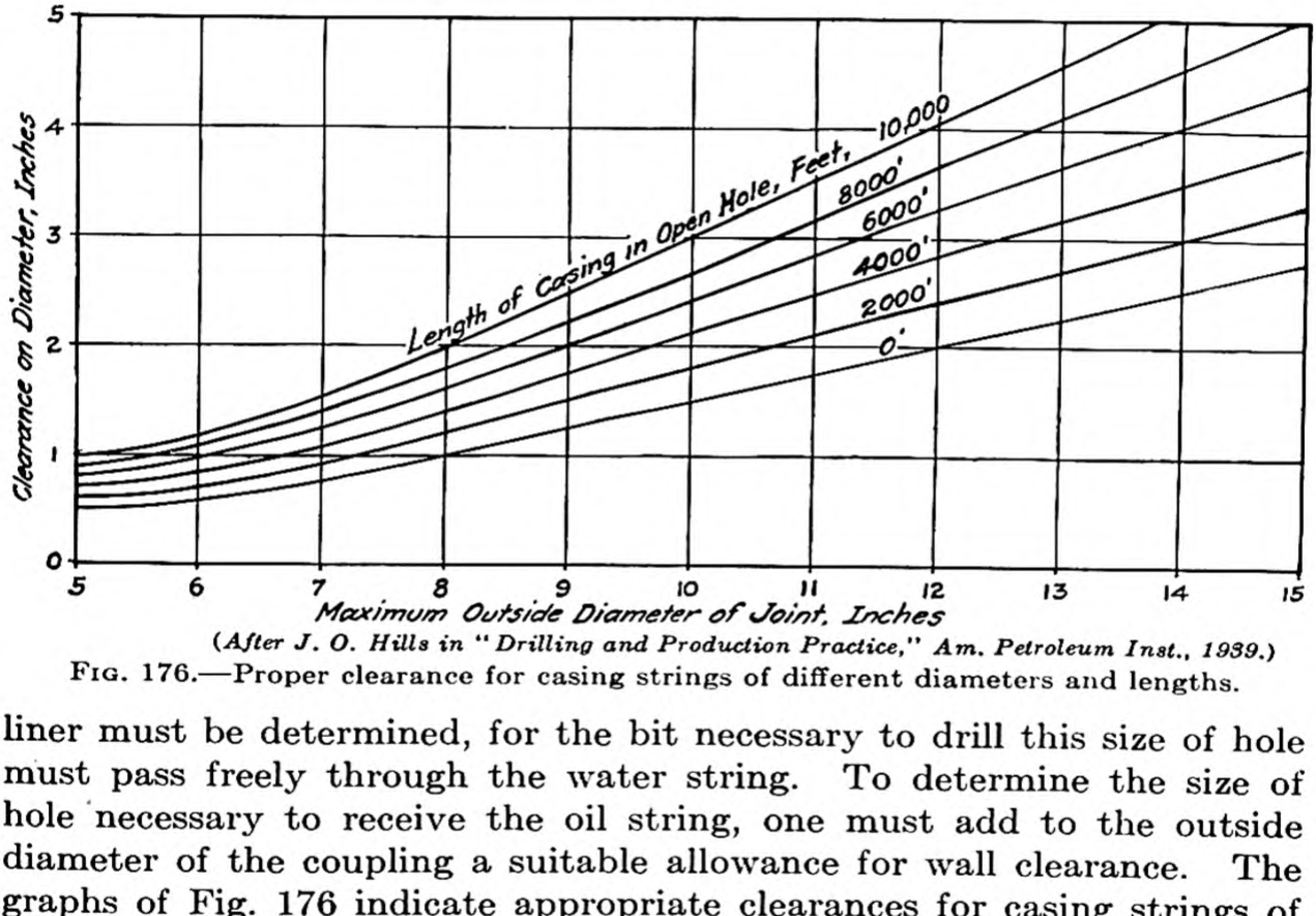
In some districts, an effort is made to complete wells with an oil string at least 6⅝ in. in diameter—even as large as 8⅝ in. if the wells must subsequently be deepened. On the other hand, where "slim-hole" practice is the rule, oil strings are commonly 5½ in. in diameter and sometimes as small as 4½ in. Where clearances are small, the liner may be composed of a flush-jointed type of casing rather than the usual collared-joint variety. The liner should be of such length as will extend through the producing interval and to a point at least 50 ft. above the shoe of the next larger string from which it is suspended by a liner hanger. Usually the liner may be a comparatively short string, but in multiple-zone situations it must sometimes have a length of many hundreds of feet. Tensile stresses being small, the liner may usually be a thin-walled tube of A.P.I. steel grade H-40 or J-55. Oil strings and liners are not ordinarily subjected to collapsing stress due to fluid pressure since they are not closed at the lower end, but they may be subjected to collapsing pressure due to the walls of the well through the reservoir rock caving about it.

If an oil string extending to the surface is used, heavier, higher quality steel (N-80) should be employed in a deep well to sustain the high tensional stress imposed. Oil strings extending to the surface are, of course, more costly, but are preferred to short liners in fields where high fluid pressures and prolific production are expected and it is likely that the string may have to be manipulated occasionally in the well. The liner or oil string should be perforated opposite the producing interval, and if the formation is unconsolidated, these openings may be screened or gravel-packed for sand exclusion. In some cases, the oil string serves also for water exclusion—a so-called "combination string"—and in this case may be cemented or equipped with a wall packer. Possible collapsing stresses must be given careful consideration when water exclusion is an objective.

Design of Water Strings.—The water string is ordinarily the heaviest column of pipe used in casing a well. Although not so long as the oil string, it is of larger diameter and heavier construction to withstand the high collapsing pressure to which it may be subjected. Being heavy,

it is also subjected to high longitudinal tensional stress; and if cemented by the "squeeze" cementing process, it may be also subjected to high bursting pressure. Inasmuch as it is used primarily to exclude water, the joints should be watertight. Drilling of the lower part of the well must be conducted through the water string after it is "landed" and cemented, and in this deeper drilling the water string will be subjected to frictional wear and vibration, perhaps sufficient to result in fatigue failure of the threaded joints.

Before the diameter of the water string may be decided, the necessary size of hole to be drilled to provide proper clearance for the oil string or



(*After J. O. Hills in "Drilling and Production Practice," Am. Petroleum Inst., 1939.*)

Fig. 176.—Proper clearance for casing strings of different diameters and lengths.

liner must be determined, for the bit necessary to drill this size of hole must pass freely through the water string. To determine the size of hole necessary to receive the oil string, one must add to the outside diameter of the coupling a suitable allowance for wall clearance. The graphs of Fig. 176 indicate appropriate clearances for casing strings of different diameter and length. If the oil string is, say, 4,000 ft. long and 6⅝ in. in diameter, the clearance should be 1 in. The outside diameter of a 6⅝-in. coupling is 7.39 in.; hence the hole drilled for it should be at least 8.39 in. or, say, 8½ in. The smallest size of water string that will pass this size of bit with proper clearance is 9⅝ in. (see Table XXXV). In this size of casing, there is a choice of seven different weights in A.P.I. standards, but the two heaviest will not pass an 8½-in. bit with proper clearance. The engineer must then determine by computations or by reference tables the cheapest of the five available 9⅝-in. casings that will have sufficient yield strength to withstand the collapsing, tensional and bursting stresses likely to be imposed, assuming

a suitable safety factor. If it be assumed that the water string is to be set at a depth of, say, 3,600 ft., reference to the setting-depth table (see Table XXXIV) indicates that 9⅝-in. 40.00-lb. grade J-55 casing will withstand a collapsing pressure of 2,770 lb. per sq. in. This is equivalent to a setting depth of 5,540 ft. and hence affords a safety factor of 1.5. The table also indicates ample joint strength and a bursting strength substantially in excess of any likely to be imposed.

TABLE XXXV.—SIZES OF DRILLING BITS TO USE FOR PROPER CLEARANCE THROUGH VARIOUS SIZES OF STANDARD A.P.I. CASINGS

O.D. of casing, in.	Weight per ft.-lb.	O.D. of coupling, in.	Size of bit to pass through, in.
4¾	16	5.36	3⅞
5	15	5.50	4¼
5	18, 21	5.50	3⅞
5½	14, 15, 17, 20	6.05	4½
5¾	14, 17, 19.5, 22.5	6.56	4¾
6⅝	20, 22, 24, 26, 28, 29	7.39	5⅝
7	17, 20, 22, 24, 26, 28, 30	7.66	6⅛
7	40	7.66	5⅝
7⅝	26.4, 29.7	8.50	6¾
7⅝	33.7	8.50	6½
8⅝	28, 32, 36, 38	9.59	7⅝
8⅝	43, 44.7	9.59	7½
9	34, 38, 40, 45	10.01	7⅞
9	55.2	10.01	7⅝
9⅝	36, 38, 40, 43.5, 47.6	10.63	8⅝
9⅝	54.2	10.63	8⅜
10¾	32.75, 40.5	11.75	9⅞
10¾	45.4, 51.0, 54.6, 55.5	11.75	9⅝
11¾	47, 54, 60	12.87	10⅝
13⅜	48, 54.5, 61, 68, 72.5	14.38	12¼
13⅜	83.5	14.38	11
16	65, 75		14¾
20	111		18⅝

When the size, weight and grade of material for the water string have been determined, the next consideration will be the size of hole to drill for it. The outside diameter of the couplings on 9⅝-in. casing is 10.625 in. Reference to the graphs of Fig. 176 will indicate that for a string of this size and length, the clearance should be 2.2 in. Hence, a bit at least 12.825 in. or, say, 13 in. in diameter should be used.

Water strings commonly range in diameter from 5½ to 10¾ in., larger sizes being only occasionally used. Inspection of the setting depth table will show that for security against collapse at great depths, only the heaviest, smaller sizes of N-80 grade steel may be used. For example,

$8\frac{5}{8}$-in. 49-lb. N-80 casing, the heaviest, strongest A.P.I. standard casing of this size, has a collapse resistance of 7,370 lb. per sq. in. The maximum setting depth for this casing, assuming a safety factor of 1.2, would be 12,280 ft.; 7-in. 38-lb. grade N-80 casing could safely be set at 15,133 ft.; $5\frac{1}{2}$-in. 23-lb. grade N-80 casing at 14,833 ft. If greater setting depths are necessary, pipe of greater weight or steel superior to N-80 should be used.

Design of Surface Strings.—The surface casing, as has been previously explained, is seldom more than 1,000 ft. long, and is seldom subjected to excessive collapsing or tensional loads. Its design is concerned primarily with protection against bursting pressure that might accidentally be applied. At or near the surface external pressures are approximately the equivalent of atmospheric pressure but, when shut in at the well head, formational gas gaining access to the casing head from great depth may create high internal pressure. Bursting pressures of several thousand pounds per square inch are possible from this source. However, the casing may be reinforced against excessive internal pressure by surrounding it with cement, and hence light casing of relatively low yield strength may generally be used, even sheet metal or stovepipe.

The diameter of the surface casing should, of course, be greater than that of the telescoping strings within it extending to greater depths. Even for two-string slim-hole programs, the initial column of casing will be at least 7 in. in diameter and for three- or four-string installations of conventional size, the surface pipe is not uncommonly as large as 20 in. With the $9\frac{5}{8}$-in. water string in a 13-in. hole, discussed above, a 16-in. surface string would probably be used. If it were, say, 1,000 ft. long it could be 16-in. 65-lb. pipe of H-40 steel, which would be secure against a bursting pressure of 1,640 lb. per sq. in. If higher bursting pressures are possible, the heavier 16-in. 84-lb. casing of J-55 steel is secure against an internal pressure of 2,980 lb. per sq. in. These values include no safety factor; however, the safety factor used in bursting-stress computations need not be high—possibly as low as 1.1.

Graduated Strings.—Often economies can be realized in designing a long, heavy string of casing for a deep well, by varying the weight and/or quality of the steel in different parts of the column. In such a casing string, the maximum collapsing stress is developed at the lower end and the maximum longitudinal tensional stress at the upper end. High stresses require thick-walled high-yield-point steel at these points, but in the middle portion of the string, a lighter weight casing or one of inferior steel may often be used with security, thus saving, perhaps, as much as 20 per cent in cost. For example, a 6,000-ft. column of 7-in. casing of high collapse resistance may be made up of 1,100 ft. of 23-lb. N-80 casing on the lower end. Above this is 1,400 ft. of 23.00-lb. J-55

casing, and this in turn is supported by 3,500 ft. of 20-lb. J-55 casing, heavy enough to support the full tensional load. Or a 12,000-ft. string of 7-in., made entirely of N-80 steel, may have 5,000 ft. of 32-lb. casing on the lower end, a middle section of 5,300 ft. of 26-lb. casing, and the upper 1,700 ft. of 29.00-lb. casing. These combinations of weights and types of steel are proportioned for security, with a suitable safety factor, yet use no more metal than necessary and utilize lower quality, less expensive steel where lower stresses permit. The stresses at top and bottom of each section should be carefully examined to assure security with a suitable factor of safety.

Often two or more different combinations of weights and grades may be designed, each equally good from the standpoint of security. In this case, the least expensive one will naturally be selected. If there is little difference in cost, the combination providing the thicker walled casings of lower grade steel will be preferred because of the superior resistance offered to wear and corrosion.

Though maximum economy might be effected with a greater number of changes in weight and type of steel, it is seldom that more than three different casings will be used in making up a graduated string. An example, however, is found in a 15,279-ft. graduated string of 5½-in. casing in one of the world's deepest wells in Pecos County, Texas. This was assembled as follows:[48]

Section No.	Grade of steel	Weight per ft., lb.	Type of joint	Maximum depth of section, ft.	Length of section, ft.	Safety factor	
						Tension	Collapse
1	N-80	23	8 rd., L.T. & C*	15,279	2,362	....	1.24
2	N-80	20	8 rd., L.T. & C*	12,917	2,837	3.43	1.25
3	N-80	17	8 rd., L.T. & C*	10,080	4,293	1.74	1.25
4	N-80	20	8 rd., L.T. & C*	5,787	1,762	1.74	
5	N-80	23	Acme	4,025	4,025	1.50	

* Eight round threads per inch, long threads and couplings.

Protective Strings.—Where a large-diameter casing must be carried to a considerable depth and there is danger of collapse, a smaller concentric string may be placed within it and cemented to the wall of the well at greater depth. The space between the two strings will be left filled with water or drilling fluid, thus creating hydrostatic head within the larger casing equal to that outside and removing any possibility of its collapse. The inner casing, even though it may extend to much greater depth, will have greater collapse resistance and may be secure

because of its smaller diameter and thick wall. The production string may serve as a protective string in this way if cemented through perforations below the shoe of the water string.

Reinforcing Casing with Cement.—The annular space about a column of casing in a well is often partly or even completely filled with cement. Perhaps many hundreds of sacks of cement will be used—sufficient to fill the annular space for hundreds or even thousands of feet above the casing shoe. Full protection against collapse is conferred by the cement to the elevation to which it fills the annular space. For example, 1,000 sacks of cement were used about the lower end of the 15,279-ft. 5½-in. casing string described in the foregoing section. This filled the annular space to 10,670 ft. and the collapse resistance was no longer a matter of concern below that depth.

Adjusting Longitudinal Tensional Stress and Bursting Pressure after Cementing a Column of Casing.—When a column of casing is cemented in a well, its full weight is suspended from the casing head. After the cement has been introduced and has risen and set in the annular space some distance above the shoe, tension in the pipe at the point of support at the surface is released by an amount that will support only the weight of casing above the top of the cement. Theoretically, this removes all tensional stress in that part of the casing column that is surrounded by cement, but there is always uncertainty whether or not the pipe is free of the walls so that it may respond uniformly to the readjustment in tension. In adjusting tensional stress after cementing, the amount of stress released may be measured directly by a weight indicator on the casing line in the derrick; or the stretch of the column of pipe due to the weight of the portion within the cement may be calculated and the column lowered an equivalent distance at the surface.

After cement has been placed in the annular space around the lower end of a column of casing, it is customary to hold pressure on the fluid in the casing until the cement has taken its initial set. Chemical change in the setting of cement creates heat which is transmitted to the fluid within the casing and, unless fluid pressure is partly vented, there is danger of developing excessive bursting pressure within the casing at the surface.

Two-string Programs.—With modern methods of rotary drilling in some fields, it is feasible to complete wells satisfactorily with only two strings of casing: a surface string and a production string, which serves also to exclude water. The lower end of the production string may be cemented and the producing interval then gun perforated (see page 572). Or it may be cemented through perforations at some intermediate point above the producing horizon. Such practices make for low drilling and casing costs, inasmuch as the quantity of steel necessary is much less

and the diameter of holes drilled is smaller than in programs requiring three or more strings. Two-string programs frequently standardize on $9\frac{5}{8}$-in. or $10\frac{3}{4}$-in. surface strings, with $5\frac{1}{2}$-in. or 7-in. production strings. The surface string is short and a single weight of pipe and quality of steel will be selected for it, but the longer production strings are frequently graduated. Table XXXVI suggests appropriate selections of size, weight and quality of pipe for casing wells to various depths when a two-string program is permissible.[31]

TABLE XXXVI.—CONVENTIONAL AND SLIM-HOLE TWO-STRING CASING PROGRAMS FOR WELLS OF VARIOUS DEPTHS*
(After J. L. Ward, Jr., in *Oil Weekly*)

Depth of well, ft.	Conventional		Slim-hole	
	Surface string, $10\frac{3}{4}$ in.	Producing string, 7 in.	Surface string, $9\frac{5}{8}$ in.	Producing string, $5\frac{1}{2}$ in.
3,000	32.75 H-40	2,000′—17.00 H-40 1,000′—20.00 H-40	32.30 H-40	3,000′—14.00 H-40
4,000	40.50 H-40	2,800′—20.00 H-40 1,200′—23.00 J-55	32.30 H-40	3,700′—14.00 H-40 300′—14.00 J-55
5,000	40.50 J-55	2,600′—20.00 H-40 2,400′—23.00 J-55	36.00 H-40	3,500′—14.00 H-40 1,500′—14.00 J-55
6,000	40.50 J-55	3,500′—20.00 J-55 1,400′—23.00 J-55 1,100′—23.00 N-80	36.00 J-55	4,700′—14.00 J-55 1,300′—15.50 J-55
7,000	45.50 J-55	3,400′—20.00 J-55 3,200′—23.00 N-80 400′—26.00 N-80	36.00 J-55	4,500′—14.00 J-55 2,500′—17.00 J-55
8,000	51.00 J-55	4,500′—23.00 J-55† 1,800′—23.00 N-80 1,700′—26.00 N-80	40.00 J-55	5,400′—15.50 J-55 2,600′—17.00 N-80
10,000	51.00 N-80	700′—26.00 N-80† 5,000′—23.00 N-80 4,300′—29.00 N-80	40.00 N-80	8,900′—17.00 N-80 1,100′—20.00 N-80
12,000	55.50 N-80	1,700′—29.00 N-80† 5,300′—26.00 N-80† 5,000′—32.00 N-80	43.50 N-80	1,700′—20.00 N-80† 6,100′—17.00 N-80† 4,200′—23.00 N-80

* A.P.I. seamless and electric weld casing.
† Long threads and couplings.

INSERTING CASING

In the case of a well drilled by rotary tools, no casing is inserted until the particular size of hole being drilled is completed. When the hole is drilled to its full depth, the casing will be lowered as rapidly as possible, and "landed" on bottom or cemented to exclude water, after which drilling is continued with a smaller bit. With cable tools a somewhat different procedure is followed in that the casing is often installed joint by joint as the hole is deepened. This is not necessarily the case when drilling in hard rock where the walls will stand up for depths of hundreds of feet without casing. In softer rocks which have a tendency to cave, however, the casing must be lowered progressively as the well is deepened, keeping the casing shoe but a short distance above the bit. When the cable tools are used, it is a poor plan to let the rope socket or jars extend below the casing shoe, because of the danger of the tools falling to one side and getting the upper end caught behind the shoe. However, the cable tools cut a larger hole if permitted to drill 20 to 30 ft. ahead of the shoe. For this reason the casing is usually suspended at about this distance off bottom unless there is danger to the casing or the tools by so doing.

Inserting Conductor Casing.—The first column of pipe placed in the well is the conductor pipe, designed primarily to exclude soft and poorly consolidated surface formations which often show a tendency to cave. As this string is seldom carried to depths of more than 1,000 ft.—often much less—it may be of light construction. To avoid wall friction and loss of working diameter, riveted or welded stovepipe or special forms of thin-walled inserted-joint steel casing, also designed for welding, are generally used. The manner of inserting such casing will depend upon its construction and the method of drilling in use.

When the well is drilled with cable tools, it is left uncased while spudding is in progress or until the walls show a tendency to cave. The tools are then withdrawn, and if riveted stovepipe is to be used, the "starter joint," which carries a light steel shoe riveted to its lower end, is started into the well. As it is lowered, additional sections are attached, picking, riveting or spot-welding them together so that the joints may not pull apart under tension. The column of pipe in the well is meanwhile supported by a pair of wooden clamps or friction blocks, securely bolted around the pipe and supported either on timbers placed on the derrick floor or by wire slings from the casing hook. The column is lowered or raised with the aid of power applied through the calf wheel. A pair of drive clamps on the drill stem may be used to drive the new joints lightly so that they telescope to the desired degree.

Only a few hundred feet of "picked" stovepipe can be lowered into an open hole if it receives no support from the walls without danger of the joints pulling apart. Usually, however, the pipe makes contact here and there with the walls so that wall friction may be counted upon to aid in holding the string together. Indeed, the friction developed is often so great that light driving is necessary to force the pipe into the well. In cases of extreme friction, hydraulic jacks may be called into service to force the column down. If the conductor string is a long one, or of large diameter and unusually heavy, a float valve may be placed in the column near the lower end,

to carry part of the weight and give added insurance that it will not pull apart under its own weight. To avoid collapse, water may be run into the pipe from time to time, maintaining it partly full.

Usually the stovepipe string will be carried to some predetermined depth if the stratigraphy is known; if not, to as great a depth as possible, though the limitations previously mentioned in describing this type of casing preclude its use to depths in excess of 1,000 ft. under ordinary conditions.

When a depth is attained beyond which it is undesirable or impracticable to carry the stovepipe string, its shoe will be grounded, if possible, in some hard stratum so that there will be no danger of the column sinking farther into the hole during subsequent drilling operations, under the influence of its own weight. After landing the stovepipe string in this way, or after it has become permanently frozen, the top is cut off level with the casing sills in the cellar so that it will not interfere with manipulation of smaller strings of pipe, and preparations are made to continue drilling with a smaller size of drill. Second and later strings of casing are nearly always of screw pipe, stovepipe being more difficult to handle at depth because of its tendency to pull apart. Then, too, it is not of sufficient strength to withstand the pressures to which it is ordinarily subjected in deep-well service.

If stovepipe is to be inserted into an open hole more than 200 ft. deep, it is better practice to support the column from the bottom while it is being lowered, rather than at the top. In this case, it is lowered on a smaller string of screw casing or tubing and is supported at or near its lower end by a cast-iron bushing or a casing spear attached to the lower end of the tubing. If a bushing is used, it is connected with the tubing by a left-hand thread, which, after the string of casing has been lowered to bottom, can be detached by rotating the tubing. After serving its intended purpose, it is easily broken up in the well with the drilling tools. The hold of the casing spear can also be broken by rotating the tubing, but in this case the tool is removed from the well with the tubing. In this way 1,000 ft. of stovepipe may be lowered into a well without injury to the casing and without danger of pulling it apart.

Where the rotary system of drilling is employed, a somewhat different system of inserting the stovepipe string is necessarily followed. The well will be full of drilling fluid, and cementing of the pipe may be required. A more substantial form of conductor pipe, such as the Hercules corrugated sheet-metal or the thin-walled inserted-joint casing illustrated in Figs. 156 and 153 is often used. These are designed for welding and in order to reduce the number of joints are furnished in lengths of 35 or 40 ft. Having drilled and reamed the well to the desired depth and circulated the well fluid until it is reasonably free from sand and coarse cuttings, and is uniform in density and viscosity, the drill pipe and bit are withdrawn and the initial joint of pipe is started into the well through a spider or wedge block placed on the rotary table or on special supports placed across the table sills. A light steel shoe is welded on the lower end of the initial joint. When not supported by the spider, the column of conductor pipe is suspended by means of casing elevators, casing line and hoisting block from the derrick crown. Since there are no collars on stovepipe, the elevators are latched about the pipe below clamps attached near the upper end. Additional joints are welded to the column, one at a time, above the spider, through holes provided in the outer or overlapping portion of the joint. After a weld has cooled, the column of pipe in the well is lifted with the elevators sufficiently to remove the slips from the spider. The column is then lowered until the upper end is about 3 ft. above the spider, when the slips are again inserted. Lowering slightly will then suspend the column on the spider, and the elevators may be used to pick up a new joint of pipe and lower it into position for welding into the string. To expedite the work of welding, a crew of four welders may work simultaneously on opposite quadrants. Such

work is often done under contract by specialized crews of welders in the employ of the manufacturers who furnish the pipe.

If the stovepipe string is to be cemented, a flange designed for attaching a cementing head is welded to the top of the column when it has reached the required depth. With the casing supported so that its lower end is a few feet off bottom, the cementing head is attached and fluid cement is pumped down through the pipe, under the shoe and up into the annular space between the pipe and the walls of the well. Where the well is to be a deep one and likely to be subjected to high-pressure conditions, enough cement may be used to fill the annular space to the surface. If this is considered unnecessary, a little cement will be placed around the casing at the surface to keep it properly centered in the hole and also to ensure against gas or mud blowouts.

After the cement has hardened, the cementing head is removed and the stovepipe cut off a sufficient distance below the derrick floor to permit of inserting a control head or blowout preventer. This is bolted to a reinforcing flange or collar, which is securely welded to the top of the stovepipe. For added security against blowouts, provision may also be made for attaching hold-down bolts, securely anchoring the casing to the concrete rig foundations.

Inserting Water Strings.—The second column of casing placed in the well is usually intended to be carried to a considerable depth and is generally used as a means of excluding water-bearing formations so that water from them may not enter that portion of the well which penetrates the lower oil-bearing horizons. Water strings are subjected to conditions which impose stresses of high magnitude, and lap-welded or seamless steel casing with thick walls and collared joints is necessarily used. The size is as large as can be conveniently telescoped through the conductor string in order to conserve working diameter. Being long, thick walled and of large diameter, this is usually the heaviest column of pipe to be handled. In some deep wells, water strings weighing upward of 200 tons have been used, in one case a string weighing 230 tons.[34]

In preparation for the insertion of a long, heavy column of screw casing, when the rotary system is used, it is customary to replace the hoisting cable with a new one, and ten lines are strung on a five-sheave hoisting block. For lighter strings, six or eight lines will be sufficient. The hoisting block and hook must also be given careful inspection if a heavy string of casing is to be run.

To ensure that the pipe will freely enter the well and reach the desired landing point, many operators run a reaming tool from top to bottom. Others run "feelers," often in the form of a short section of the pipe to be inserted, to assure themselves that the column will reach bottom. Some operators also under-ream for 100 ft. or so above bottom, to remove mud from the walls and leave the rock surfaces free to make proper contact with the cement. A long, heavy string of casing may be very difficult to lift without danger of parting, and every precaution is taken to be certain that the hole is of requisite diameter throughout before the pipe is lowered. With the same purpose in view, the drilling fluid in the well will be thoroughly circulated to remove all drill cuttings and detrital material, and to secure a fluid of uniform characteristics throughout. This is done immediately before the drill pipe is withdrawn, after all reaming is completed and special rigging for handling casing has been assembled. The casing should be lowered to bottom as quickly as possible after circulation is stopped; otherwise clay and sand may settle and prevent the casing from reaching the desired depth. The fluid in the well should be of reasonably low viscosity and free from sand. Its density should however be high. in order that it may develop a maximum buoyant effect on the casing and thus reduce the load on the surface equipment.

With all in readiness and with the drill pipe out of the hole, the rotary table is removed and a heavy spider or casing block is placed on heavy timbers resting on the

table sills over the well. Often the casing block will be permanently mounted on a timber or steel sled. If the column of casing to be lowered is not too heavy, the table slips may be used to support the pipe or a casing block may be placed on top of the table. The first joint of casing lowered into the well has a suitable casing shoe welded, riveted or screwed to its lower end. Often a cement shoe, equipped with a float valve, such as that illustrated in Fig. 158 and described on page 477, will be employed. In addition, a float disk carrying a downward-opening valve may be placed in a casing collar, a joint or two off bottom. The special shoe and collar are designed to assist in the subsequent cementing operation and also serve to close the lower end of the column, preventing admission of the well fluid so that the pipe may be "floated in." The surface equipment is thus relieved of a large part of the load that it would otherwise have to bear.

The shoe joint, suspended on the elevators and casing block, is lowered through the spider until the open collar on the upper end is about 3 ft. above the derrick floor. The spider slips are then dropped into position and the joint again lowered until the slips take hold. The elevators are detached, a new joint of casing is brought in from the rack outside the derrick and up-ended by hoisting on the elevators until its lower end swings freely above the collar of the shoe joint suspended in the spider. The thread protector on the lower end of the new joint is removed, a thread compound is applied to both parts of the joint and the new section of pipe is then lowered carefully into the collar on the upper end of the pipe supported in the spider, avoiding abrasion of the threads. The upper joint of pipe is given a few turns by hand, using a rope sling and bar if necessary. When the threads have engaged and it is certain that they are not cross-threaded, casing tongs are applied, first by hand, then with the aid of the power, until the joint is securely made up. The power may be applied by means of a line spooled over one of the rotary catheads, or, in the case of the combination or standard rigs, with a jerk line attached to the wrist pin on the crank. For small- and medium-sized casing one pair of casing tongs will be sufficient, but for large sizes two may be used. Some operators make up casing joints with a "spinning rope," several wraps of the rope being taken about the pipe above the joint and power applied with one of the rotary catheads. Some rotary tables are equipped with features designed to assist in making up and breaking down drill pipe, which may also be used on casing when the latter is of small or moderate size. Some special types of rotary equipment such as the Hydril (see page 350) are particularly designed to assist in casing operations. The driller's judgment will largely determine when the joint is secure, though some operators insist that all threads should be "buried in the collar," while others judge by the temperature developed in the collar. When the joint is securely made up, the column of pipe is lifted slightly until the spider slips can be removed and then lowered until the top of the new joint is about 3 ft. above the spider. The slips are again inserted and the casing in the well suspended on the spider. This process of adding a new length of pipe to the column in the well is continued, joint by joint, until the shoe on the lower end reaches bottom.

An augmented crew is generally employed in running casing, often from seven to ten men. The several members of the regular rotary crew work in their usual places: one at the draw-works and engine controls, three on the derrick floor and one in the derrick. In addition, when a combination rig is used, a cable-tool crew of two men may be employed in operating the standard engine and jerk line from the crank in making up joints. Additional men may be used in rolling casing down off the rack and bringing it into the derrick, removing thread protectors and doping joints. With a skilled crew, the work moves with clocklike precision. From 8 to 20 joints per hour are made up, depending upon the size of the casing. Wells 6,000 ft. deep may thus be cased in from 15 to 30 hr. with large-diameter pipe; in one instance, 6,237 ft.

of $11\frac{3}{4}$-in. 60-lb. casing was placed in a well in 13 hr. The rate of progress, expressed in footage, will depend upon the length of joints, the time necessary being nearly halved through the use of 40-ft. joints instead of 20-ft. joints. The longer joints are uncommon, though where there is room to stand casing in the derrick, some operators make up 40-ft. "doublers" and stand them on end in the derrick so that actual placing of the casing in the well may be accomplished in the shortest possible time. This, however, is practicable only when small-diameter pipe is in use.

When the column of casing is floated in, it is customary to keep the pipe only partly full of drilling fluid. As much as 2,000 ft. of pipe may be left open to develop the desired buoyancy when a long column of heavy pipe is to be set, but usually 500 to 1,000 ft. will be sufficient. As the column of pipe is lowered into the well, fluid is of course displaced so that there is, with each lowering of the pipe, a flow of drilling fluid upward, which assists in keeping it free of the walls. With the purpose of reconditioning the fluid and offsetting the tendency of solid components to settle out, some operators occasionally attach a circulating head to the top of the casing column, circulating new fluid down through the pipe, under the shoe and back to the surface. This is particularly desirable when the lower end of the column is nearing bottom, it often being necessary to "circulate in" the last few joints when sufficient time has been occupied in the casing operation to allow the mud to settle. If the casing tends to become "logy," a little crude oil or Aquagel added to the recirculated fluid will assist in keeping it free. In a deep well it may be somewhat uncertain just when the casing shoe reaches bottom unless careful measurements have been made of the depth of the hole and the length of pipe inserted. A weight indicator, such as that described on page 315, will assist in determining this.

The column of casing is finally suspended with the lower end a few feet off bottom, and preparations are made for cementing (the cementing process is described in detail in Chap. XII). When the cement has set and hardened, tension equal to the weight of the column is taken from the upper end and maintained by attaching a suitable head device, which bears on the upper end of the conductor casing. These head supports provide massive bearing flanges with packing compressed between, or, in some patented forms, mechanical stuffing boxes in which the inner casing is supported on slips which may be placed to take hold at any desired point (see page 598).

When the cable system of drilling is employed, the procedure followed in inserting casing is much the same as that described for the rotary-drilled well in the foregoing paragraphs, except insofar as modifications are required by the nature of the equipment available and the condition of the hole. With the cable tools, casing is handled on elevators and a hoisting block strung on a steel line passing over casing pulleys at the derrick crown and thence to the shaft of the calf wheel. If no calf wheel is provided as a part of the rig, the casing line is attached to the bull-wheel shaft. If the formations are hard and do not show a tendency to cave, the hole may be drilled to its full depth before any casing is inserted, but, if the formations are unconsolidated, it will be necessary to carry the casing along with the drilling, adding a joint or two at a time as drilling progress permits. The column of pipe in the well is suspended on a casing spider, which is often placed on timber supports in the bottom of the cellar, so that the upper end of the casing can be kept below or level with the derrick floor and thus be out of the way of all operations in the derrick. As the hole is deepened, drilling will be interrupted occasionally to add more casing to the column so that the shoe is always kept below the jars. The advantage offered by the casing spider, of being thus enabled to lower the casing gradually as drilling proceeds, is often helpful in penetrating a caving formation and allows the tools to work on bottom without interruption. This procedure is possible with the cable tools because in soft formations they are capable of drilling a hole of larger diameter than that of the casing

through which they operate. When hard strata are encountered, in which the cable tools tend to drill a smaller hole, it may be necessary to under-ream before the casing shoe can pass through.

Additional Water Strings.—If four strings of casing must be used in a well, as may be the case where the well is a very deep one, where formations developing caving conditions must be contended with, or where upper oil and gas sands must be protected, the strings intermediate between the second and the last are also regarded as water strings and are inserted in the manner described in the previous section. These additional water strings are customarily cemented, and in many cases sufficient cement will be used on the smaller inner strings to fill the annular space up to and preferably somewhat above the shoe of the outer, larger water string. The space between the two columns of pipe may then be filled with mud fluid. This practice transmits the outside collapsing pressure to the inner water string which, by virtue of its smaller diameter, is better able to sustain it.

Inserting Casing by Welding Joints.—The process of inserting a string of pipe, the joints of which are oxyacetylene welded, is necessarily quite different from that described above for collared-joint casing. The pipe must first be prepared for welding. As already explained, plain-end pipe is used and, unless it is properly beveled for welding in the mill where it is made, each joint must be placed in a lathe, machined to square ends and then beveled on the outside for two-thirds of the thickness of the pipe. In order to reduce the number of welds made in the derrick, the pipe is welded into two-joint stands and three or four lugs are welded on the outside of each stand near one end so that the elevators may be used in suspending it in the derrick.

The first stand is hung in the well on slips, either in the rotary table or a casing spider, and a rod of welding iron, bent into a U form, is laid across the upper end. The next stand has meanwhile been hoisted into the derrick on the elevators and is lowered on the U-shaped rod, which serves to space the two joints at the proper distance apart for welding. Spacing of the ends in this way leaves room for expansion, so that the casing will not be thrown out of alignment when making the weld. Two welders work on opposite sides of the pipe, an arrangement which also aids in preventing crooked pipe as a result of unequal expansion. After the casing is aligned, two "tacks" are spot-welded on opposite sides of the joint, after which the welding metal is fused, beginning at positions 90 deg. from the tacks. The space between the square ends of the joints is first filled with metal, after which the corners of the beveled portion are rounded off to increase the surface of contact, and the space between the two joints is filled flush with the outer cylindrical surface. After the weld is completed, the lugs on the lower joint are cut off with the cutting flame, the weld is allowed to cool and the casing is lowered on the elevators for the next weld. Another type of welded joint makes use of a short reinforcing tube spot-welded on the inside of the joint.[35,40,43]

With 8¼-in. casing, about 1 hr. is required for each weld (*i.e.*, for each 40-ft. stand). Welding saves about $5 per joint (for 8¼-in. pipe), by eliminating collars and threads, but this is partly offset by the cost of beveling the ends for welding. The extra cost of labor and materials used in welding, however, about equalizes the saving effected. Eight hours is necessary to run in 300 ft. of 8¼-in. pipe, as against 1½ hr. for a like amount of screw casing. Two welders, one helper and a drilling crew of five men are necessary in conducting the work, while steam supply, oxygen, acetylene, welding iron, etc., must also be taken into account. In the case of a well equipped with a welded liner in one of the California fields, the additional labor and materials amounted to about $75.

It is claimed that welded liners will stand more jarring and pulling than collared joints without danger of parting and do not freeze so readily, and that there is less loss of

working space in the well because of elimination of the collars. In removing a welded liner from the well, it must be cut apart in stands of convenient length. This may be done with the cutting torch but is preferably accomplished with pipe cutters which leave the ends straight and properly beveled for welding when the string is replaced.

Landing Casing.—When a string of pipe has been carried to as great a depth as is necessary, or as is deemed desirable, and a change in the diameter of the bore is to be made, the casing must be properly supported so that it will not follow down the hole under the influence of its own weight during subsequent drilling operations. If possible, a stratum of hard rock will be selected in which to land the column of pipe, and a slightly smaller hole will be drilled a few feet ahead, into which the casing shoe will be driven. When the change is made to the smaller size of bit to be used in drilling the next section of hole, the casing will be supported on a narrow shoulder of hard rock and with the shoe thoroughly embedded in it (see Fig. 169).

Cementing Casing.—If a string of pipe is to be used to exclude water, the procedure is somewhat different. The method of landing the pipe described in the preceding paragraph may be successful in excluding water (see "Formation Shutoffs" on page 463), but most operators prefer to exclude water by surrounding the casing at its lower end with a plug of cement, which completely fills the space between the casing and the walls of the well. The cement is placed, by methods to be described in detail in Chap. XII, with the casing shoe a few feet off bottom; but the shoe is lowered to bottom and driven into a tight hole previously prepared for it before the cement has taken its initial set. This leaves a few feet of cement which must be later drilled out of the casing. A period of from 4 to 16 days is usually allowed for the cement to harden before drilling is resumed.

Perforating the Oil String.—The last column of casing to be placed in the well is that which penetrates the oil sand and is therefore called the "oil string" or "liner." This pipe must be perforated with a series of round holes or slots, opposite the oil-production stratum, in order to admit the oil to the pump. The pipe may be perforated in the shop before lowering it into the well, or the openings may be made in the well with the aid of a casing perforator. The methods of perforating casing, the placing of screens and other details incidental to the completion of the well and preparing it for production are to be described in Chap. XIV.

Salvaging Pipe in Casing a Well.—It is not necessary that all strings of casing in a well come to the surface. Unless water is to be excluded by a column of casing, it may be cut off about 50 ft. above the shoe of the preceding string and considerable casing salvaged (see Fig. 169). A water string, however, must always extend to the surface so that water may not accumulate behind it and overflow into the lower part of the well. A string of pipe which is not intended to extend to the surface may have placed in it at the proper point a "bell collar" having left-hand threads in one end, so that by rotating the column of pipe after the shoe has been placed on bottom the column is broken at the bell collar and the upper end is removed. Casing may also be cut at any desired point by the use of a tool made for the purpose and called a "casing cutter" (see Fig. 218).

DIFFICULTIES ENCOUNTERED IN HANDLING CASING IN THE WELL

Casing difficulties are the result of freezing, collapsing, telescoping, parting or splitting. Freezing results from caving of the walls against the pipe, accumulation of mud around the casing collars, contact with the walls in a crooked hole or failure properly to ream a tight place in the well. Collapse of the casing is due to external pressure, generally hydro-

static pressure, though caving of the walls or a loose boulder in the walls bearing against the pipe as it is forced down may deform it. Telescoping of a column of pipe may result from dropping it accidentally or, in the case of stovepipe, from driving it too severely at the top when the lower end is frozen. Parting, or pulling apart of a column of pipe, may be the result of extreme tensional strain engendered by its own weight or by trying to pull it up when it is frozen. It may result from defective threads or from failure to couple the joints properly; or the lower end of the column may be loosened by turning the pipe in the well, or by the jar resulting from hammering on its upper end in driving it down. A column of stovepipe may pull apart by failure of the picked joints to hold together. Premature explosion of a charge of dynamite or nitroglycerin will generally part the casing opposite the point of explosion. Splitting of casing usually indicates defective welding in the manufacturing process, but it may be caused by drilling out material which has heaved up from the bottom into the casing, or it may result from the use of a swedge, casing spear or other fishing tools (see pages 536 and 537). Most of these difficulties may be avoided by proper selection and inspection of casing and care in coupling the joints together and lowering the column into the well. Good judgment is also necessary in determining to what depths a string of pipe may be carried under the conditions applying and what strain can be safely put upon it. The condition of the walls of the well, whether or not the hole is crooked or all tight places have been adequately reamed, will also have an important bearing on the success of a casing installation.

Freeing Partly Frozen Casing.—If the casing develops frictional contact with the "formation," that is, if it shows indications of being collar bound with mud and loose material from the walls, it can often be freed by alternately raising and lowering it a few times for a distance of 20 or 30 ft., working the loose material past the collars and shoe so that it falls into the bottom of the well. If this fails to relieve the friction on the pipe, the well may be bailed down within the casing so that hydrostatic pressure aids in clearing the space about the pipe; or a hole may be drilled below the casing shoe so that there is adequate space into which the mud may flow. The pressure conditions may be reversed by placing a circulating head on the top of the casing and pumping water down through it under pressure in the hope of establishing circulation back to the surface through the space around the pipe. If circulation can be established, the mud will be gradually removed by the upward current. If difficulty is found in securing circulation under the pump pressure available, a slit cut in the casing shoe or in the pipe immediately above is often effective.

If friction on a column of casing is due to an effort to lower it through too small a hole, the best remedy is to pull the pipe up until the shoe is above the tight place and under-ream it thoroughly. Under such conditions, particularly if the pipe has been driven, it is often impossible to lift the column against the friction with the power available from the calf wheel and hoisting blocks, or without placing undue strain on the derrick. In such a case a combined pull and jar is often successful where a simple pull fails. This is accomplished by lowering a casing spear (see description of spear on page 537) below the stem and a pair of fishing jars, taking hold with the spear

inside of the pipe near the bottom and jarring up with a long stroke of the beam. Tension is meanwhile held on the casing with the hoisting blocks and elevators (see Fig. 213), or a lifting force may be applied to the casing by means of screw or hydraulic jacks.[36]

Driving Casing.—If friction on the pipe is thought to be due to a crooked hole, or if it has been gradually increasing and the landing depth selected has been almost reached, the pipe may be driven from the surface in the hope of reaching the required depth before the pipe becomes completely frozen. Alternate driving and pulling of casing are also effective in freeing it from wall friction. Driving the casing down will often leave a free space above the collars, so that the pipe can be readily drawn back the same or often a slightly greater distance. Alternate driving and pulling back in this way will in many cases gradually free frozen casing until it can be moved up and down the length of a joint of pipe, when it should pull quite freely. In driving casing, spring and vibration of the pipe are the means of loosening the enveloping sediment. The method of driving casing from the top with the drive clamps and head has already been described. Driving from the top is likely to be detrimental to the pipe, often loosening the joints, or in some cases stripping threads in the collars; furthermore, much of the force expended at the top of the column is absorbed at depth by the elasticity of the pipe.

A long column of pipe can be driven more satisfactorily by applying the vibration near the bottom instead of at the top. This can be accomplished through the use of the jar-down or drive-down casing spear (see Fig. 211*D*). The tools are strung as in fishing, with long-stroke fishing jars below the stem and with the spear screwed on the bottom of the lower link of the jars. The slips on this spear are so constructed that they slip up a conical recess and out against the inner face of the casing, preventing the tools from going farther down the hole. The process of driving down with this equipment consists simply in gripping the casing with the spear at the desired depth and operating the walking beam with a stroke sufficient to cause the jars to strike on the downstroke. The position of the spear must be changed frequently to prevent the pipe from becoming distorted by the outward pressure of the spear slips.[36]

Lubricating Casing with Oil to Reduce Friction.—Observation has shown that pipe will freeze less readily in rocks saturated with oil. In some instances petroleum has been circulated in wells with the hope of reducing friction of the walls against the pipe. This method has apparently met with some success in certain California fields where it has been found possible, by circulating oil, to keep a long string of pipe fairly free in the well, while ordinary unlubricated casing in the same territory freezes rapidly. It seems probable that the oil saturates the material in the walls, rendering them more plastic, thus releasing the hold on the pipe. Furthermore, loose sand, which tends to pack about the casing collars in the presence of water, remains in suspension in oil. Casings, apparently firmly frozen, have been released by circulating oil with pump pressure under the shoe and back to the surface. In one case a column of 12½-in. casing was frozen in a 15-in. hole and the derrick collapsed in attempting to release it. After the derrick had been rebuilt, oil was circulated for 3 days and the string was readily pulled out.

The dangers involved in pulling on frozen casing are well understood by most drillers. When one considers the great mechanical advantage of the ordinary band-wheel, calf-wheel and hoisting-block combination—ordinarily about 144 times the lifting force of the engine—it is apparent that we are dealing with a force of great magnitude, sufficient either to pull the pipe apart or collapse the derrick. Men have been killed or injured by the collapse of the derrick or by contact with the calf line, hoisting blocks or elevators in the sudden release of tension when the casing pulls

apart near the surface. The equipment should be operated from the engine house in pulling casing.

Parting and Sidetracking Frozen Casing.—Should it become impossible, by any of the methods suggested above, to move the pipe either up or down in the hole, and it is essential to continue to a greater depth with the size of pipe in use, the pipe must be parted above the point at which it has become frozen and the lower end sidetracked. It is possible to locate approximately the depth at which the pipe is frozen by lowering a fishing string and jar-down spear, taking hold inside of the pipe at intervals, jarring, and noting the change in character of the vibrations produced in the pipe.[38] When the spear takes hold above the "friction," the jarring produces a metallic ring in the pipe that is quite absent when the spear is attached below. If the approximate depth at which the casing is bound is known, it may be cut with a casing cutter, or ripped with a casing slitter or perforator, and pulled apart a short distance above; or it may be parted with a charge of dynamite or nitroglycerin. The explosive should be used in small quantities—10 to 15 lb. of 40 per cent dynamite is sufficient in most cases. The upper end of the column of pipe may be withdrawn after parting by either of these methods, a new shoe placed on the bottom and the column replaced until the new shoe is about 75 ft. above the top of the parted string. The lower part of the well is then redrilled, with caution, until the detached column of pipe is passed.

Sidetracking Casing.—When a portion of a string of pipe has been either accidentally or intentionally parted and it is found to be impossible for one reason or another to remove it from the well, an effort must be made to drill past the parted string. This may be a difficult procedure in hard rocks, but is easy of accomplishment in soft formations. Since it is necessary for the new casing to make a slight bend in passing the old pipe, an effort should be made to enlarge the hole by underreaming for a distance of 60 or 75 ft. above the top of the parted pipe. The drilling tools are then put to work as in ordinary drilling, upon the top of the old pipe, gradually battering and distorting it until the tools work off to one side. Difficulty may be encountered in getting the new casing shoe to pass the top of the old pipe, but turning the string at the surface will often allow the shoe to slip past. Once by the upper end of the parted column, little difficulty results, the new hole being drilled at one side of the parted column and the latter eventually cased off. Contact between the collars or ragged edges on the parted string and the shoe on the new string may cause slight delays, but patience in manipulating the casing at such times will usually overcome the difficulty. Various types of reamers and eccentric bits are used by some drillers in sidetracking pipe to aid in enlarging the hole and clearing the way for the new pipe. Often, better progress is made in drilling by the old pipe than in drilling the original hole. In some cases, hundreds of feet of casing are successfully sidetracked in this way and occasionally several separate sections of pipe will be cased off in a single well. The method described may also be employed in sidetracking lost drilling tools or other well equipment impossible to recover by fishing.

Operations involved in the repair or replacement of collapsed, telescoped or parted casing partake of the nature of fishing, and are reserved for description in Chap. XIII devoted to Fishing Tools and Methods.

Measuring Casing. Stretch and Sag in a Column of Pipe.

—It is occasionally necessary to know the exact length of a string of pipe or the precise depth at which the shoe of the string is located. The repair of old wells, the exclusion of water occurring in strata immediately above an oil sand and the depth at which to place perforated pipe, detonate

explosives or apply casing cutters or other special tools are operations which often require fairly exact casing measurements. In order that such information be available, it is a good plan to record it as a part of the log of the well (see page 626), which is carefully preserved as a record for future reference.

Although it is possible to determine approximately the length of a column of pipe by measuring each joint that goes into it (length from top of collar to top of lower threads), the sum of such measurements will seldom give the exact length of the column owing to variation in the length of threaded ends in the couplings. A better method is to measure the length of each stand or joint with a steel tape after the joints have been set up with the tongs and are ready to be lowered into the well. Even such a measurement is not altogether reliable if it is to be used as a means of correlating with a stratigraphic record, say, in determining the precise depth at which to make a water shutoff or to place perforated pipe opposite an oil sand. This results from the "stretch" of a column of casing under its own weight, which tends to make the column longer than the tape measurement would indicate; and the "snaking" of the pipe in the hole, which results in some cases in a somewhat greater length of casing being placed in a hole than the actual drilled depth. An approximate calculation of the elastic elongation of a column of pipe hanging free in a well, for example, indicates that 6,000 ft. (tape measured) of steel pipe would actually be 24 in. longer. Linear expansion in a column of this length subjected to an average increase of, say, 50°F. in ground temperature will add another 23 in. to the length of the pipe. It is a matter of common observation, in pulling a column of casing out of a deep well, that several feet or, at times, even a joint or more may be pulled up at the surface before the full weight of the pipe is felt. This can be nothing else than stretch in the pipe, or surplus pipe that results from "staggering" of the casing from side to side in the hole. Many drillers consider a stretch of 1 in. to 100 ft. a normal elongation in pulling frozen pipe. If a well departs from the vertical by, say, 5 deg. in a depth of 3,000 ft., the bottom may actually be 12 ft. nearer the surface than the length of the pipe in the hole would indicate.

The actual depth to the lower end of a column of casing may be checked by an independent measurement after the column is in place in the well, if precise data are necessary. In such measurements it is customary to lower some tool—such as a ripper, an under-reamer, a latch jack or a specially designed hook—which can be made to catch on the lower edge of the casing shoe, carefully measuring the length of the cable on which the tool is suspended. An under-reamer of the same size as the casing gives especially satisfactory results. The lugs expand after passing below the shoe and, when the tool is pulled up so that the

lugs strike against the shoe, the resulting vibration indicates definitely its position. An electrical log of a well shows precisely the position of the lower end of the casing.[37]

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CHAPTER XII

OIL-FIELD HYDROLOGY

Among the most complex problems with which engineers engaged in oil-field development must contend are those encountered in the exclusion of subsurface waters from wells and from oil- and gas-producing formations. If water enters from an overlying source, it may accumulate in the bottom of a well until it develops sufficient static head seriously to restrict influx of oil and gas from the producing formation. Sometimes the head developed is so great that water enters the producing strata and forces the oil and gas away from the vicinity of the well. Water entering an oil sand in this way wets the exposed surfaces of the reservoir rock and fills the pore spaces so that they do not subsequently yield readily to the passage of oil through them. If, in this way, a large volume of water is permitted to enter an oil-bearing formation through a well, it may migrate through the producing formations and influence the production of wells at a considerable distance from the point of entrance.

Aside from its influence on oil and gas production, the presence of water in the oil produced by a well increases the cost of operation, often necessitating the pumping of a large volume of worthless fluid which must be separated from the oil after it reaches the surface. Water-oil mixtures in the well often form emulsions from which the oil may be extracted only with great difficulty and expense. Ground waters are often corrosive and metal casings and well equipment in contact with them sometimes deteriorate rapidly.

Because of the difficulties that result from the presence of water in oil and gas wells, it should be excluded by suitable means. The necessity for water exclusion is recognized by all oil producers and is prescribed by law in most oil-producing states and countries. Water-exclusion methods have received a great deal of attention and are now well developed, particularly in certain regions where the menace of water incursion is recognized as a problem of vital importance.

Occurrence and Behavior of Water in Sedimentary Strata.—Everywhere at a variable distance below the earth's surface, the rocks are supposed to be saturated with water. This water is classified as "connate" water if it is occluded within the pore spaces of sedimentary rocks during the process of sedimentation, or "meteoric" water if it has drained down from the earth's surface by gravitational seepage. The upper surface of this body of ground water, called the "water table," is irregular in

contour but roughly parallels the configuration of the earth's surface. In most places it is found near the surface, but in arid regions it may lie at a depth of several hundred feet. Below the water table, earth formations are assumed to be saturated with water until temperatures and pressures are reached at which water cannot exist in liquid form and may be present only as a vapor. Although all formations below the water table are known to contain more or less water, the degree of saturation and the hydrostatic pressure are widely variable and circulation of ground water is confined largely to the more permeable beds.

Highly permeable, sandy strata, which are often completely saturated with water under high pressure and yield their water freely to penetrating wells, are called "water sands" to distinguish them from strata that are less permeable and yield their contained water less freely. It is probable, however, that the so-called "dry" sands are only relatively dry. Clays and shales, which are not usually thought of as water bearing, often contain more water than sandstones, but do not yield it so freely.

Pressure within a water-saturated stratum will, in general, increase with depth below the water table in the formations in which they occur. This is due to the hydrostatic head of the superimposed column of fluid which, if fresh water, should be equivalent to 0.436 lb. per vertical foot of depth below the water table. There are, however, many exceptions to this general statement, particularly in cases where formations have become sealed by cementation, compaction, faulting, etc., to such a degree that there is no continuous channel of fluid for transmission of pressure through the formations from the water table, which may be many miles distant. After deep-seated formations have become sealed, the fluids imprisoned in them may be subjected to pressures far in excess of the normal hydrostatic head for the depth at which they are found, by compaction of the surrounding sediments due to the weight of overlying strata, or by compression of strata due to tectonic forces.

Water present in subsurface formations is often migratory, flowing from areas of high pressure toward areas of lower pressure. Much of the water present in the upper portions of the earth's crust is replenished seasonally through outcropping permeable beds by percolating surface waters, and there is necessarily considerable lateral and vertical movement of ground waters in adjusting the differences in pressure which naturally result. Connate water, which is found particularly in the deeper sedimentary formations, may also be forced to migrate by cementation or consolidation of sediments due to the accumulating weight of overlying strata; but often connate water is held practically trapped within synclinal troughs or basins of folded structures, or in strata otherwise sealed or isolated.

Relation of Water to the Oil-bearing Strata.—Water-yielding strata may be found either above or below and occasionally within an oil-producing zone and, with respect to this zone, waters so occurring are referred to, respectively, as "top water," "bottom water" and "intermediate water." The water that underlies the oil in the lower horizons of an oil- or gas-bearing stratum is commonly called "edge water." Edge water in a stratum that yields oil at up-dip locations often appears as intermediate water in multizone oil accumulations. In horizontally disposed or low-dipping strata, the lower portion of a thick, oil-bearing stratum may contain water, the oil apparently floating on top of the water. It is probable however, that in many supposed cases of this sort, there is an impervious bed separating the oil-bearing portion from the water-bearing portion, so thin perhaps, that it has not been logged in the process of drilling.

Chemical Constitution of Ground Waters Associated with Oil Deposits.—In strata to which surface waters have access, the water is characteristically fresh, but in deeper horizons where movement is sluggish the waters may acquire considerable percentages of dissolved solids from the surrounding rocks. Connate waters occluded within marine sediments at the time of sedimentation were initially saline and in many cases have remained so throughout subsequent geologic ages. Such waters, by interaction of different dissolved salts, are often the cause of secondary cementation and replacement in porous rocks to which they have access.

The universal association of brine with petroleum deposits is a matter of common knowledge and some geologists believe that commercial deposits are to be found only below the fresh-water level. Oil-field ground waters frequently contain several times as much dissolved salt as ordinary sea water. It is reasonable to assume that appreciable changes in the chemical composition of these connate waters have occurred throughout long periods of geologic time.

There are marked differences in the concentration of dissolved salts and in the nature of the salts present in oil-field brines. The waters of different strata are usually distinctive and often differ markedly from each other in chemical constitution and reactivity. The dissolved salts commonly present in ground waters are primarily the chlorides, sulphates, nitrates, carbonates and bicarbonates of the alkalies and alkaline earths (sodium, potassium, magnesium, calcium, barium and lithium). Iron, alumina and silica are often present in small amounts and occasionally hydrogen sulphide or sulphur dioxide will be found in solution. The preponderance of one or another of these elements or radicals is often a reliable characteristic of the water in a particular stratum, and the different strata in a given locality may in many cases be readily identified and

correlated from well to well by making analyses of their contained waters and noting common characteristics. For example, a persistent top water overlying the oil measures in the Coalinga field of California contains dissolved hydrogen sulphide and is so well known throughout the district by this characteristic that it is often used as a "marker" horizon in making correlations from one well to another.

Frequently the dissolved salts present in ground waters appear to bear a certain relationship to the proximity of petroleum. It is found in some oil fields, for example, that the waters immediately associated with the oil measures are notably lacking in sulphates but are often high in carbonates. There is some evidence to show that this may be attributed to the reducing effect of decomposing organic matter from which petroleum is formed; or it may result from slow reduction of the sulphates by prolonged contact of ground waters with petroleum itself under certain conditions of pressure and temperature. Reduction of the sulphate to sulphide is accompanied by the formation of carbonate, and the proportion of carbonate is thus abnormally increased. An unstable sulphide of iron may also be formed as a result of this reaction, imparting to shales and clays a characteristic blue color. The presence of barium and strontium may explain the absence of sulphates in some cases. It is also known that certain anaerobic bacteria, which are apparently able to live in petroleum, have the ability to convert sulphates into sulphides. In the Appalachian fields concentrated chloride waters associated with the oil and gas contain noteworthy amounts of calcium. The waters are characteristically lacking in sulphates but usually also lack carbonates. In some of the San Joaquin Valley fields of California the surface waters contain sulphates, but in the sands immediately above the oil zone sulphates practically disappear and are replaced by carbonates. Edge waters and bottom waters in this region are high in chlorides. So persistent are these characteristics that in certain fields operators find it advantageous to make chemical analyses of all waters encountered in the drilling of wells and are able to predict, in some measure, the position and proximity of the source of the sample with respect to the oil zone.[3]

It is a matter of common belief that petroleums suffer an increase in density by contact with ground waters. This may be explained from the chemical point of view as a result of the reduction of dissolved sulphates in the water in contact with the oil. As a product of this reaction, hydrogen sulphide is formed and the carbon formerly linked with this hydrogen forms carbon dioxide or carbonate. It is a well-established fact that oil in contact with sulphides will increase its density and viscosity by the formation of complex hydrocarbon-sulphur compounds.*

* ROGERS, G. S., Relation of Sulphur to Variation in the Gravity of California Petroleum, *Trans. Am. Inst. Mining Met. Eng.*, vol. 57, pp. 989–1009, 1917.

Temperature undoubtedly plays an important role in influencing the solution capacity of ground waters for soluble salts. Temperature increases in a constant ratio with depth, and temperatures ranging between 100 and 300°F. are not uncommon in oil-field ground waters produced from a depth of 3,000 to 15,000 ft. Waters that become saturated with a soluble salt at such temperatures may, on subsequent cooling, precipitate cementing material between the grains of porous rocks to which they have access.[2] Chemical interaction between dissolved salts as a result of contact between different ground waters has a similar effect. It is thought that the accumulation of large quantities of salt from waters in oil and gas wells, and the sealing of the pores of productive oil and gas sands by deposition of salt, also result from such reactions. However, in some cases it is probably due to the evaporative effect of natural gas on water within the well, evaporation of the water causing concentration and eventual supersaturation of the well fluid accompanied by deposition of salt.

IDENTIFICATION OF WATER-YIELDING FORMATIONS IN DRILLING

In the usual routine of drilling, it is often a difficult matter to determine whether or not a particular stratum encountered is capable of yielding water to the well, the fluid pressure existing within it and the rate at which water may flow from it under a given pressure differential. In cable drilling, it is customary to maintain a certain depth of water in the hole, which may be sufficient to prevent low-pressure water from entering. For example, a 1,000-ft. column of water exerts a pressure of 434 lb. at the bottom of the well if the water is not saline or mud-laden. If the pressure within a water sand encountered in the bottom of the well is less than this, no water will enter the well from it. On the other hand, if the differential pressure is sufficiently great, water may flow from the well into the sand.

If the fluid level in the well sinks as a sand stratum is penetrated by the drill, it is logged as a dry sand; but this usually means only that it contains water under relatively lower pressure than that produced by the static head of fluid in the well, and that the permeability is such as to permit of movement of water from the well into the formation. If, on the other hand, the fluid level rises when a new stratum is encountered, it is evident that water is flowing into the well from this source and that the fluid in it must be under greater pressure than that represented by the column of fluid in the well; also, that its permeability is sufficiently great to permit of flow of water through it under the differential pressure conditions existing. A study of fluid levels during the process of drilling and of the time rate of rise from one fluid level to another will thus give valuable data on possible sources of water that might prove troublesome

during a later period. If it is safe to do so, fluid should be bailed from the well whenever a new sand is encountered, until the nature and pressure of its fluid content may be determined. At such times, samples of the fluid should also be gathered for analysis and future comparison.

In rotary drilling, the well is necessarily maintained full of fluid, and on account of the mudding of the walls and necessity for continual circulation of drilling fluid, estimation of the water-yielding capacities of the formations penetrated is a more difficult problem than in cable drilling. However, if a stratum is highly permeable and the pressure of fluid within it is materially lower than that developed by the static head of fluid in the well, it will usually absorb fluid from the circulating system, so that the level of fluid in the mud pit falls and more water must be added. This should be accompanied by a decrease in the pump pressure necessary to maintain circulation. If, on the other hand, a highly permeable stratum contains water under high pressure, the differential pressure between it and the well may be so small that it is not noticeable on the pump pressure gauge; and if little or no fluid is absorbed from the circulating system, there may be nothing to warn the driller of the presence of a high-pressure water sand that may later cause trouble unless it is properly cased off.

It is usually impractical to bail a rotary-drilled well frequently in order to obtain samples of formation fluids, or to make tests of fluid pressure. Mechanical formation samplers (see page 561) are available which are designed to isolate a small section of the well and so control the pressure conditions within it as to permit of securing an uncontaminated sample of the formation fluid. Depth-sampling devices are also available for taking a sample of the fluid in a well at any desired depth.* By bailing fluid from the well, the static pressure may be reduced sufficiently so that fluid will enter from the formation. A sample taken in the well opposite a water-yielding stratum will then be fairly representative of the fluid within this stratum, though perhaps not entirely uncontaminated.

When a permeable, water-saturated stratum is penetrated by a well and pressure maintained within the well is lower than the hydrostatic pressure existing within the stratum, water will flow from the stratum into the well. The rate of flow will depend upon the permeability of the stratum and the differential pressure existing. This differential pressure is usually a maximum and the rate of flow will be greatest when the stratum is first penetrated by the well. Flow of water into the well will at once reduce the fluid pressure in the stratum, and pressure reduction will continue until an equilibrium pressure gradient is attained,

* For a description of a typical depth sampler, see pp. 154–155 of the companion volume of this work, entitled "Oil Field Exploitation."

at which water enters the stratum from other sources as rapidly as it flows into the well. The rate of pressure decline may vary over a wide range, depending upon the permeability of the stratum and the volume of water accessible to it. In a highly permeable formation sealed from its outcrop and other sources of water replenishment, a high initial pressure and rate of flow into the well may quickly decline. Or a permeable bed communicating with a vast expanse of surrounding water-

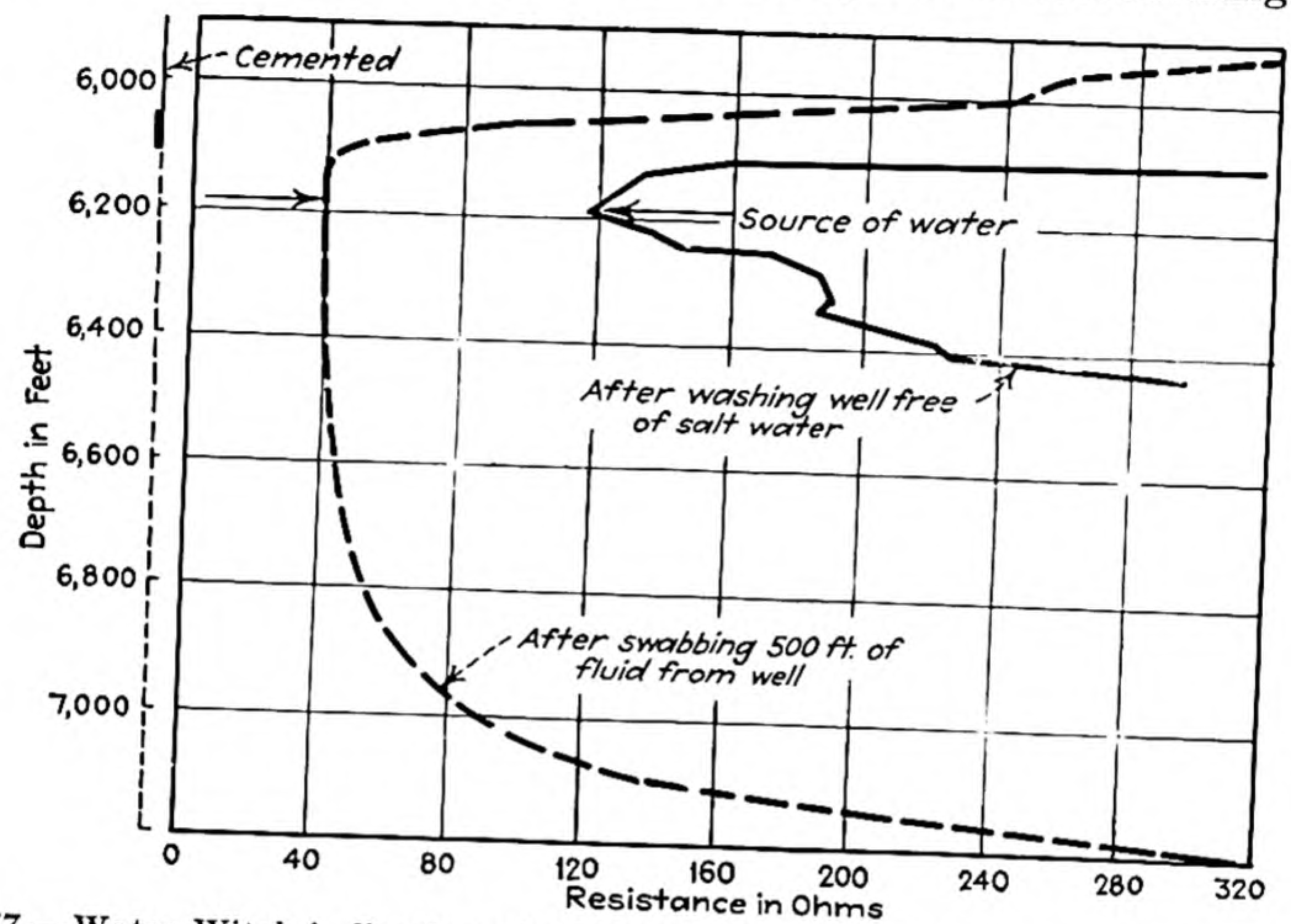


FIG. 177.—Water Witch indication of a high-head top-water leaking under casing shoe.

saturated formations may continue to deliver fluid into the well at almost undiminished rate for long periods of time.

Devices for Locating Source of Water Entering a Well

Before undertaking water-exclusion operations, it is necessary to know the exact depths to top and bottom of the interval in which water is entering or is capable of entering the well. If this has not been disclosed by routine tests of the character described in the foregoing section, resort may be had to the use of one or another of several electrical devices designed for this purpose.

The Water Witch.—A convenient instrument for determining the point of admission of water in a well is called the "Water Witch," a device which indicates differences in the electrical conductivity of the well fluid at different depths. Because most ground waters encountered at depth are highly saline, their electrical conductivity is generally higher than normal. Where fluid in the well and in the formations penetrated thereby are in static equilibrium, it is necessary, before making the test, to bail or swab some of the fluid from the well and thus establish a flow of water from the formation into the well. The instrument comprises two electrical terminals sup-

ported at some distance apart in a metal shell to which the well fluid has access. It is lowered through the well on the lower end of an armored and insulated cable containing a two-wire electric circuit. An electric current is caused to flow through the circuit from a bank of storage batteries or a motor-generator set situated at the surface, while an ammeter indicates the amount of current flowing, from which the resistance of the circuit may be computed. The entire equipment is brought to the well on a motor truck especially equipped with a hoisting drum for reeling the cable into and out of the well. The electrical resistance of the circuit is determined continuously as the instrument is lowered through the interval to be tested, and the results are plotted as a depth profile. In the interval where formation water is entering the well, a marked change in the conductivity of the circuit can generally be observed (see Fig. 177).

The Lo-kate-it Device.—In the use of this instrument for determining the point at which water enters a well, the well fluid must be first conditioned through the interval in which a test is to be made, by uniformly distributing through it a solution of potassium bichromate containing a small amount of sulphuric acid. These reagents develop an electromotive force which is measured by an instrument which contains one zinc electrode and one gold-silver alloy electrode, suitably spaced apart and connected one at either end of a two-wire electric circuit encased in an insulated conductor cable extending to the surface. The magnitude of the electromotive force developed by the electrolyte in the well fluid, which is indicated by a sensitive voltmeter in the circuit at the surface, varies with the concentration of bichromate solution. In traversing the well with the instrument, at points where water is entering and diluting the reagent, a lower electromotive force is recorded. The equipment is permanently assembled on a motor truck equipped with a power-driven winding drum for the insulated cable.

The Dale Water-locating Instrument.—This device utilizes a photoelectric cell and a small incandescent lamp focused on it. Light falling upon the photoelectric cell causes it to generate an electric current, the intensity of which varies as the light intensity varies. The instrument, suitably protected by a surrounding casing to which the well fluid has access, is lowered into the well on an insulated cable carrying conductor wires. An ammeter connected in the circuit at the surface indicates the amount of current generated by the cell. Mud fluid or oil in the well obscures the light so that the electrical impulse generated is small, but in intervals where water enters from the formation, the well fluid is locally made more transparent, more light reaches the cell and the electrical impulse is increased. In this, as in other methods of electrically determining the point of water entry, conditions must be established within the well that will permit water to enter from the formation. If a state of pressure equilibrium has been attained within the well, the fluid must be bailed down somewhat, so that more water may enter.

Electrical Resistivity Methods of Locating Water-bearing Formations.—Electrical logs of wells made by resistivity measurements, as described in a later section (see page 630) also provide a convenient means of identifying water-bearing formations encountered in the course of drilling. Intervals in which the observed resistivity values are low are water-bearing, particularly if the water is saline, as is usually the case. If, for the same interval, the "porosity" profile or self-potential record is higher than normal, the indications are that the formation is sufficiently permeable so that the water present in it will flow readily into the well.

METHODS OF EXCLUDING WATER FROM WELLS

It has been shown that water entering an oil well may have its source in formations above or below the oil-producing zone and that in some

cases it may originate within the oil-producing formations as edge water; or it may be present as intermediate water between two producing zones. The method of water exclusion to be adopted will depend somewhat upon the source of the water and its relation to the producing formation. Top waters are generally excluded by setting a water string or column of casing which extends through the water-producing interval in the well, the annular space between the wall of the well and the casing being closed through the water-yielding interval with cement or with a mechanical packer of appropriate type closing the annular space below the water-yielding horizon. Or the water string may be equipped with a heavy reinforcing shoe at its lower end and driven into a reduced-diameter hole prepared to receive it in a suitable stratum of clay, shale or other impermeable material below the water-yielding formation. Bottom waters and edge waters may be dealt with by methods that involve plugging the lower part of the well with cement or mechanical plugs and packers of various types. Intermediate waters are excluded by filling with cement the annular space between the wall of the well and a column of casing where it passes through the offending zone. Methods involving the forcing of mud-laden fluid, cement or chemical solutions, coagulants, fibrous materials, etc., into very permeable strata have also been successfully used in excluding water under favorable circumstances.

Exclusion of Top Waters

Use of Packers.—Early methods of excluding top water involved the use of various forms of packers between the casing and the walls of the well. Bags of dry seeds or cereals were sometimes lowered into the well and manipulated until they passed under the casing shoe and up behind the casing above the shoe. On contact with water these materials expand and close the space about the pipe so that the descent of the water is checked. Packers made of loosely wrapped canvas or hemp rope, placed on the outside of the pipe before lowering into the well, may be compressed into a shorter length, causing increase in diameter by proper manipulation of the pipe (see Fig. 178). Mechanical packers, designed to expand a rubber cylinder against the walls of the well under the influence of the weight of the casing, or by rotating the casing, are available and may be effectively used in excluding water under favorable conditions. All packers are constructed of materials which can scarcely be regarded as permanent in the sense that they will function effectively throughout the life of the well, and permanent water exclusion is necessary inasmuch as continued oil production is contingent upon it. Ordinarily it will not be possible to replace the packer at such times as it may cease to be effective since it is usually difficult to withdraw the casings

from a well after the walls have had time to settle about them. Because of the temporary nature of packers, and the difficulty and uncertainty of setting them properly, they are seldom used for permanent exclusion of top water.

Mechanical packers are widely used for water exclusion in the older oil fields of Eastern United States, where the wells are of small capacity and relatively shallow, where the wall rocks are firm and where the

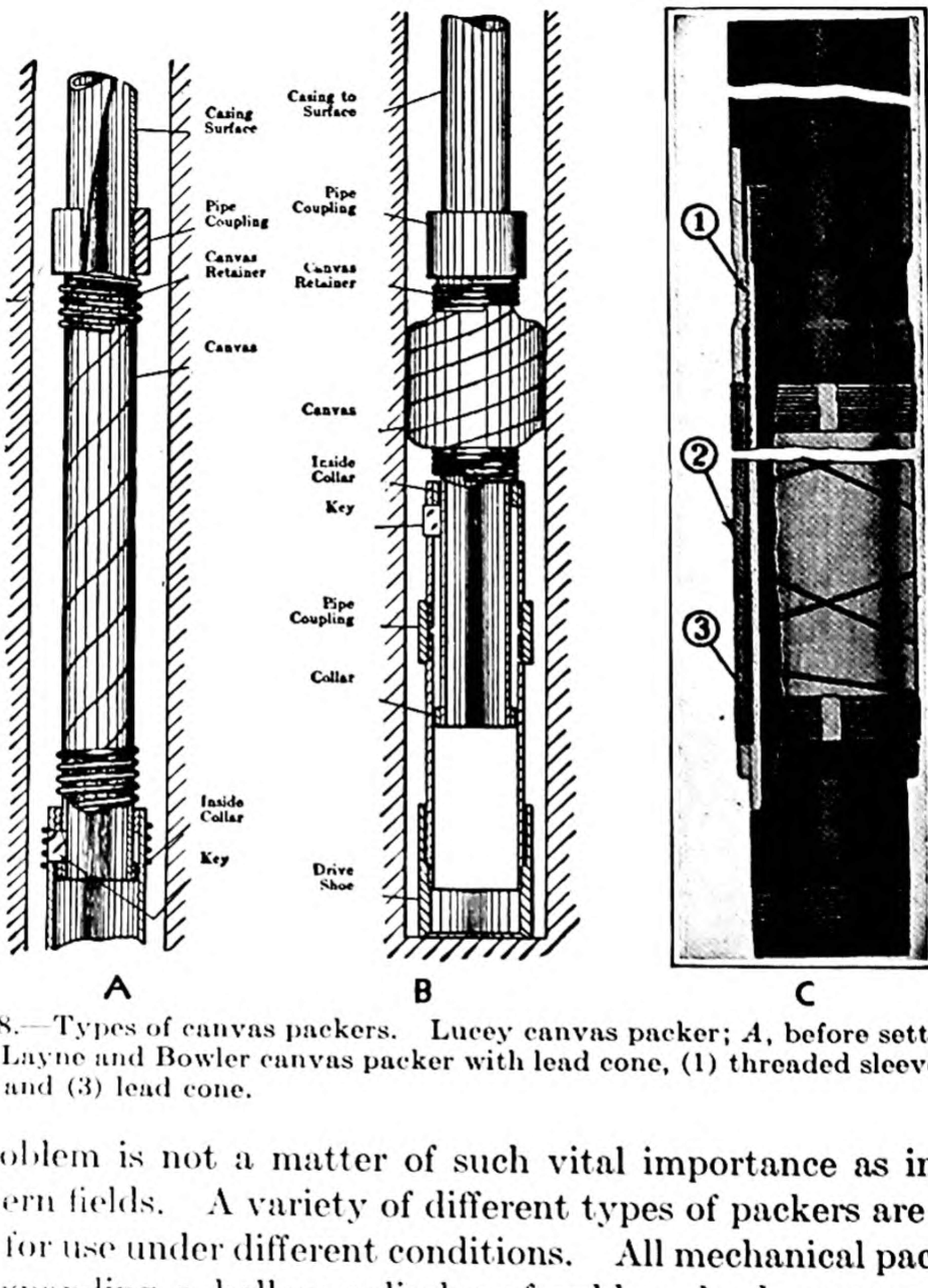


FIG. 178.—Types of canvas packers. Lucey canvas packer; *A*, before setting; *B*, after setting; *C*, Layne and Bowler canvas packer with lead cone, (1) threaded sleeve for setting, (2) canvas and (3) lead cone.

water problem is not a matter of such vital importance as in many of the Western fields. A variety of different types of packers are available, designed for use under different conditions. All mechanical packers operate by expanding a hollow cylinder of rubber, lead, canvas or burlap at the desired point in the well, either by compression from the ends against a tapered metal sleeve, or by rotation of screw devices. They are lowered and manipulated on either casing or tubing and may be used to seal off the space between two strings of pipe or between the pipe and the walls of the well. Rubber packers range from 3 to 8 ft. in length, the rubber sleeve varying from 1 to 3 ft. in length. Canvas packers are

commonly about 8 ft. long, with a canvas or burlap sleeve 3 ft. in length, though special packers of this type may be secured which are as long as 20 ft., with an 8-ft. sleeve of canvas or burlap.

Bottom-hole packers (see Fig. 179) are used on the lower end of a string of pipe to close the space between the pipe and the walls of the well. The packer is held in its extended position by copper rivets through the conical metal sleeves, but these are sheared, permitting the sleeves to telescope and expand the rubber cylinder when the full weight of the pipe is allowed to rest on bottom. The lower end of such a packer is equipped with a substantial reinforcing shoe, while the upper sleeve is threaded to connect with the casing. The rubber cylinder fits snugly over the top or inside sleeve and is about 3/8 in. smaller in diameter than the hole it is designed to close when expanded.

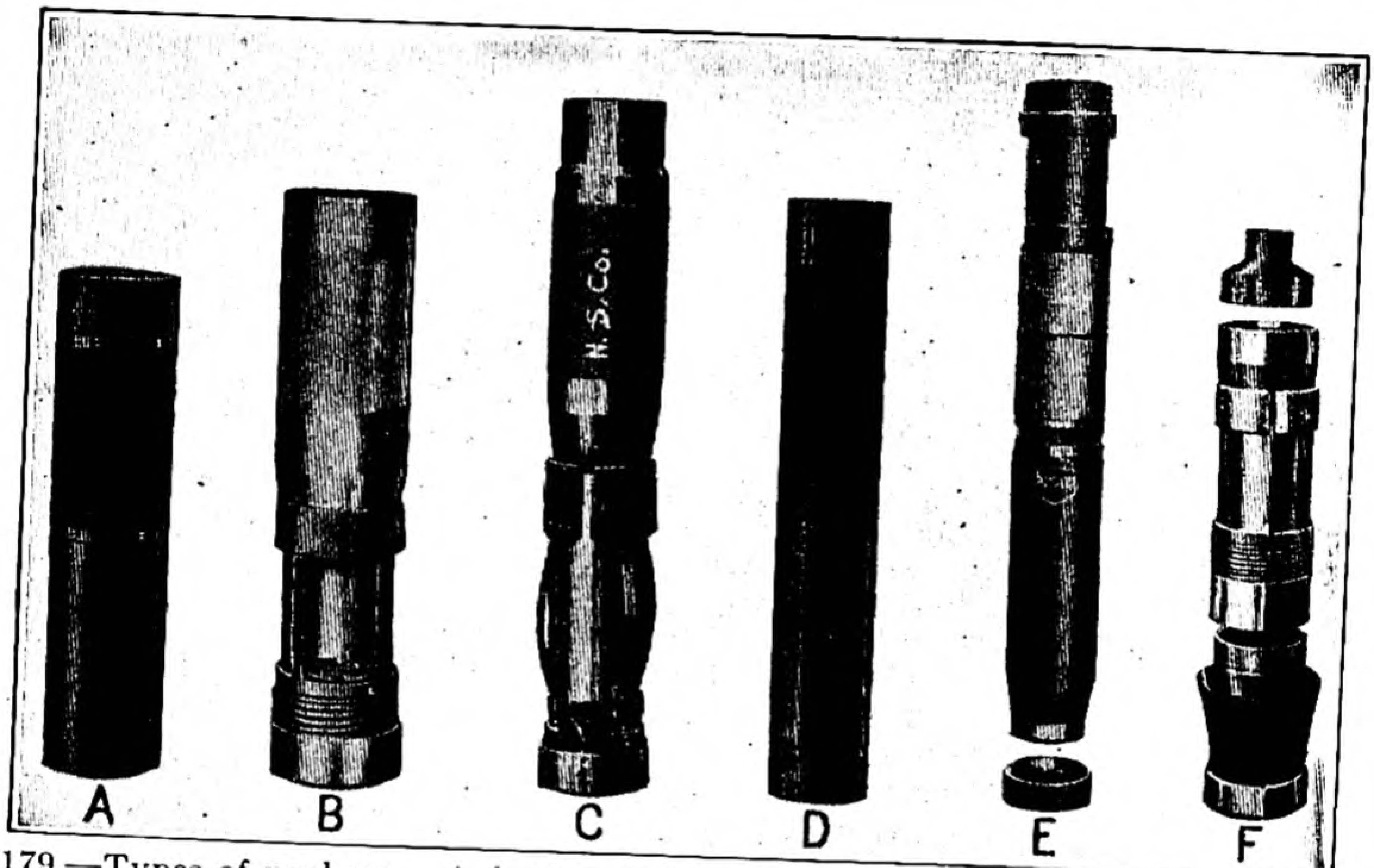


Fig. 179.—Types of packers. *A*, bottom-hole packer; *B*, disk-wall packer; *C*, hook-wall packer; *D*, anchor packer; *E*, Robinson screw-down packer; *F*, cave packer.

Wall packers are used to close the space between two strings of pipe, or between the pipe and the walls of the well at some point above bottom. They are of several forms, the better known types being the disk-wall packer, the hook-wall packer, the anchor packer and various forms of screw packers. Wall packers are often equipped with a series of slips operating on a tapered cone, which are intended to support the weight of the casing or tubing on which the packer is placed. Screw connections are provided at top and bottom for tubing or casing.

The disk-wall packer (see Fig. 179) is lowered to the desired position, coupled into the column of casing at the proper point. The slips are held on the lower portion of the conical sleeve by a hinged steel disk, across the inner opening of the hollow sleeve composing the body of the packer. A weight—such as a piece of 1-in. pipe, 6 or 8 in. long—dropped from the surface when the packer is in position, breaks or dislodges the disk and releases a spring surrounding the lower sleeve and compressed between the slips and the bottom collar. This spring forces the slips upward on the tapered cone. Further lowering of the column of pipe causes the friction springs to advance the slips farther up the conical sleeve pressing them outward until they

bear against the walls of the well or against the outer casing. The slips thus support the casing or tubing, while the weight of the pipe above the packer compresses the rubber cylinder, causing it to expand until it fills the space about the pipe.

The hook-wall packer operates in a similar manner, except that the slips are held on the lower part of the conical sleeve by a hook latch, which is released by turning the casing or tubing through 180 deg. (see Fig. 179). This packer is lowered into the well on the tubing or casing, with the hook latched. When about a foot above the point where the packer is to take hold, the pipe is given a half turn to the right, thus disengaging the hook and releasing the slips. Friction springs prevent the slips and hook from turning with the pipe. After the hook is disengaged, the pipe is lowered until the slips slide up the tapered sleeve and engage the walls. This form of packer can be released by raising the casing and turning to the left until the hook is engaged, after which it can be set at a lower position if desired. The packer can be readily withdrawn from the well without engaging the hook.

Anchor Packers.—Disk and wall packers are used on casing or tubing which does not rest on the bottom of the well. If the pipe rests on the bottom of the hole, an anchor packer may be used at any desired point in the column of pipe. This type of packer is similar to the bottom-hole packer described above, except that the latter is equipped with a shoe on the lower end while the anchor packer has a pipe connection. It is frequently used to close the space between two strings of pipe, or between the casing and the walls of the well, placing the proper length of casing below the packer to bring it to the desired depth in the well when the string of pipe rests on bottom. Another form, known as the "disk-anchor packer," cannot be released until a hinged disk is broken by a blow with the bailer or drilling tools, or by dropping a weight upon it from the surface.

In another form of anchor packer, the two sleeves are fastened together with a coarse square thread (see Fig. 179). The metal above the thread is turned down, so that by screwing the upper sleeve down until the threads no longer engage, the two sleeves telescope freely under the influence of the superimposed weight of the pipe, bringing pressure to bear upon the ends of the rubber cylinder. This form of packer may be conveniently used on the same string of casing with a bottom packer, as, for example, when a wall packer is to be set above a water sand, and a bottom packer on a shoulder of rock below. The bottom packer is set in the manner described above; then, by taking a light strain on the casing and turning the pipe two full turns to the right at the surface, the top packer is released from the threads and seated against its rubber cylinder. Release of tension on the pipe then expands the rubber against the walls.

Screw Packers.—The packers thus far described accomplish expansion of the packing material merely by the superimposed weight of the casing. Another type of packer is designed to operate without the aid of the weight of the casing and without the necessity of an anchor extending down to the bottom of the hole. This is the screw-down liner packer, which expands the packing material by screwing the upper of two conical metal sleeves into the lower. This packer is lowered into the well and set by means of a special "letting-in" tool mounted on a column of tubing (see Fig. 179). With this type of packer it is possible to lower a short column of casing with a packer at each end and to set both packers firmly against the walls in such a way as to exclude the water or a caving formation, though the casing does not extend either to the bottom of the hole or to the surface. Such a packer is useful for excluding water or caving material at shallow depths where the weight of the superimposed casing or tubing may be insufficient properly to expand a wall packer of the ordinary type.

Since a packer forms a permanent part of the well equipment, it must be con-

structed of material that will be long lived and must not obstruct the free passage of tools or other well equipment through it. In some instances, packers must be gastight, a feature which is accomplished by a special rubber seal between the telescoping metal parts. Packers equipped with rubber cylinders are best adapted for use in hard rocks that do not crumble under the side pressures developed. For use in loosely cemented, unconsolidated formations, such packers are little used, the canvas packer being generally preferred.

Formation Shutoffs.—For many years prior to the development of cementing methods it was customary in the fields of Western United

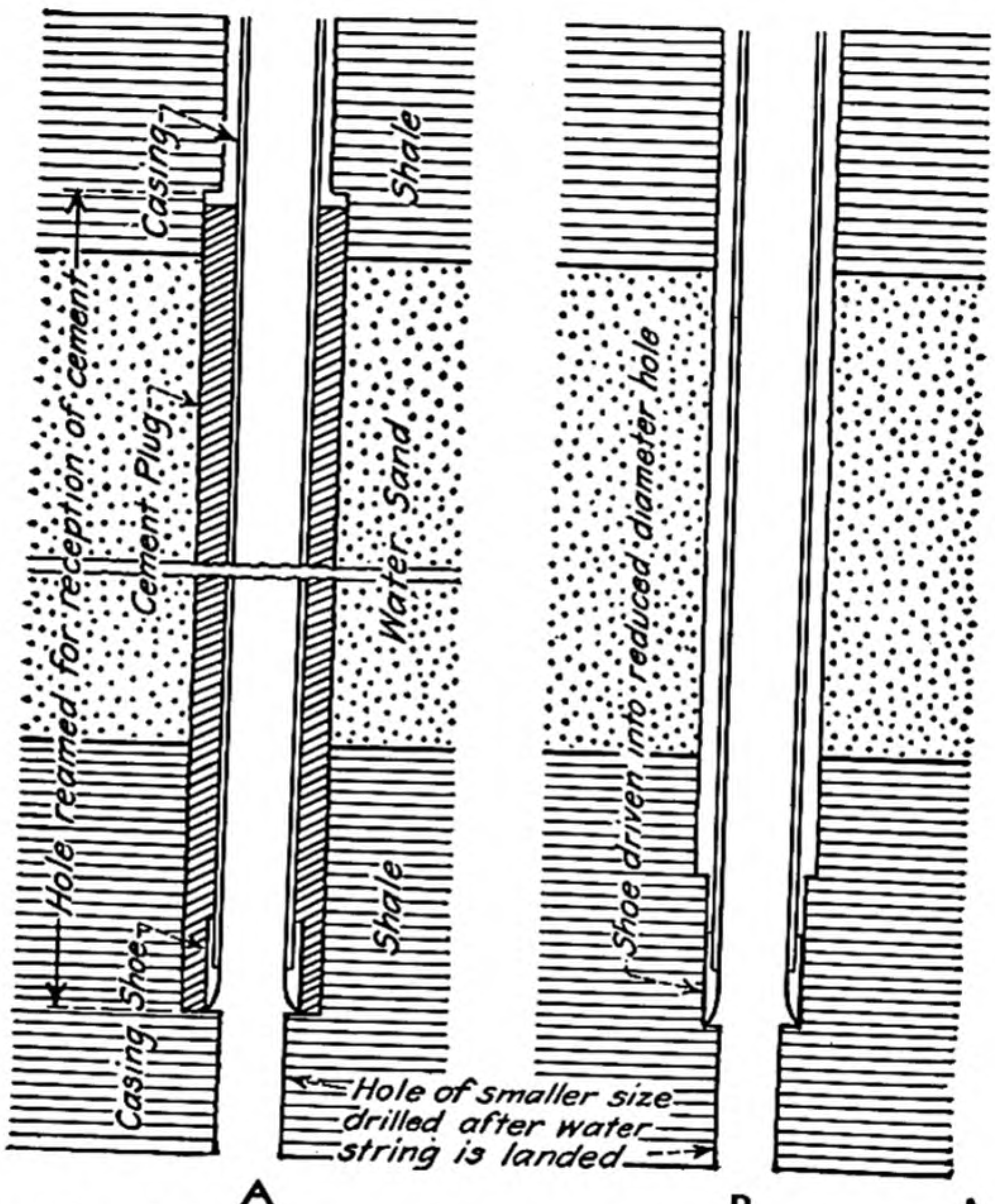


Fig. 180.—Methods of excluding top water in cased wells. *A*, cement water shutoff: *B*, formation shutoff.

States to exclude water from oil wells by what is called the "formation shutoff." In excluding water by this method it is first necessary to reach a bed of some substantial, impervious material, such as hard shale or "shell," in which to accomplish the shutoff. When the casing has been properly landed on such a stratum, a hole slightly smaller than the casing is drilled for a few feet below the shoe and the casing is driven into the pocket thus prepared (see Fig. 180*B*). The frictional pressure about the lower end of the casing thus developed, usually aided by accumulation of clay and detritus from the sludge in the well, is often

sufficient to seal off overlying waters effectively. This method of water exclusion, however, is not always successful, and even though it may apparently be so at the time it is made, in a later period, when water has had time to accumulate back of the casing, it may and often does become ineffective.

Cementing Casing

The most effective methods yet devised for the exclusion of top waters make use of cement, which is forced in a fluid condition into the annular space between the walls of the well and the casing, and allowed to set and harden, forming a permanent and impervious barrier to the downward movement of top water (see Fig. 180*A*). Portland cement mixed "neat" (without sand) in from 35 to 50 per cent of water is commonly employed.

Several different methods have been developed for accomplishing the insertion of the cement into the well. In an early method the liquid cement was lowered in specially constructed bailers which dump on reaching bottom. Later methods made use of auxiliary tubing through which the cement was pumped to the bottom of the well. In more modern methods, widely employed at the present time, the cement is pumped directly through the well casing.

The procedure to be followed in cementing a water string will depend to some extent upon the method of drilling used. If cable tools are employed, a low fluid level may be carried in the well, the fluid consisting chiefly of water so that the walls are not thoroughly mudded. In such a case it may be difficult or impossible to fill the well with fluid and secure circulation down through the casing and back to the surface. On the other hand, when the rotary method is being used, the hole is necessarily left full of fluid and the walls are thoroughly mudded so that they are impervious to the passage of fluids either into or from the well. The well fluid in this case is a mud-laden fluid and it may be unsafe to displace it with clear water. Smaller quantities of cement are generally used where the cable tools are employed so that the bailer method or tubing methods are often applied. When the rotary method of drilling is used and circulation back to the surface is easy of attainment, the methods of pumping cement directly through the casing—preferably with barrier plugs—are commonly used.

Bailer Method of Cementing Casing to Exclude Top Waters.—Where but a small quantity of cement is to be placed for the purpose of sealing off top water, a dump bailer may be used in lowering cement slurry to the bottom of the well. Appropriate types of dump bailers are described in a later section (see page 482). Accumulated detrital material is first bailed from the well; the column of casing to be cemented is lowered into

the well and suspended with its lower end 20 ft. or so off bottom. The cement slurry is mixed in a metal or wooden box placed at a slight elevation above the derrick floor, and flows through an inclined trough leading directly to the mouth of the well. A lip on this trough serves to guide the cement into the bailer which is suspended with its open top immediately below the discharge end of the trough. Usually the bailer must make several trips to the bottom of the well, inasmuch as several tons of cement will ordinarily be necessary.

When all the cement has been placed in the bottom of the well, the lower end of the casing is closed with a plug or packer of suitable type, lowered on a drilling cable or sand line, and the column of casing is lowered to bottom through the fluid cement. If the well and casing can be maintained full of water or drilling fluid, the column of casing may be closed at its upper end instead of the lower end. In either case, the fluid cement is unable to enter the lower end of the column of casing as it is lowered to bottom and, by displacement, is forced to assume the desired position in the annular space about the lower end of the column of pipe. After the casing has been lowered to bottom, it should be driven for a few feet into the underlying formation as further insurance against the cement finding its way back into the casing before the initial set occurs. This method is particularly adaptable to the placing of small amounts of cement in wells where the shutoff is intended to be of temporary character or where high water pressures behind the casing are not expected to develop. The bailer method is particularly useful in cable-drilled wells where the walls are not thoroughly sealed by accumulated clay and it may be difficult or impossible to fill the well with water to secure circulation back to the surface.

Tubing Methods of Cementing Casing to Exclude Top Waters.—A widely used method of placing cement in the annular space about the lower end of a column of casing involves suspending the casing with its lower end a few feet off bottom and forcing fluid cement slurry under pump pressure down to the bottom of the well through an auxiliary string of tubing inside the casing, extending down to the level of the casing shoe. Fluid cement is prevented from entering the annular space between the casing and the tubing by a suitable packer or retainer that closes this annular space at the level of the lower end of the tubing ("bottom-packer" method), or by filling the casing with water and closing the annular space between it and the tubing at the surface ("top-packer" method). Cement pumped down through the tubing, unable to enter the annular space within the casing, flows under the casing shoe and up into the annular space outside of the casing. To assure success of the operation, it is desirable that the well and casing may stand full of fluid and that circulation be established and maintained down through

the tubing and back to the surface through the annular space between the casing and the wall of the well.

Many tons of fluid cement may be used in a single operation; it is mixed with water and pumped continuously down through the tubing, followed by water or drilling fluid in volume just sufficient to displace all of the cement from the tubing. A wooden plug that slips snugly through the tubing may be inserted between the cement and the fluid used to pump it down, in order to prevent cement dilution and contamination. The plug ultimately lodges in a constriction in the lower end of the tubing or on a back-pressure valve incorporated in the retainer or packer, building up pump pressure and indicating when all cement has passed out of the tubing. When all cement is in place outside the casing, the latter is lowered to bottom and driven a few feet into the underlying formation. Provision is made for disengaging and withdrawing the tubing before the cement sets, leaving the packer or retainer lodged in the lower end of the casing. The back-pressure valve mentioned prevents cement from flowing back into the casing. After the cement has set, the retainer or packer and any residual cement left in the lower end of the casing can be drilled out with either cable or rotary tools.

Pumping Cement through Casing between two Moving Plugs.—The most widely used method of cementing casing involves forcing neat cement slurry down through the casing between two moving plugs of special design that fit snugly within the casing. This method constitutes a patented process known as the Perkins process. Though the original patents governing its use have now lapsed, many supplemental patents covering later improvements in equipment and methods used in the art of well cementing are still operative and are largely controlled by service organizations specializing in this work. The casing is suspended in the well with the lower end a few feet off bottom. The well and casing must be full of fluid and, before any cement is introduced, circulation must be established down through the casing and back to the surface through the annular space between it and the wall of the well. One or more high-pressure pumps near the well head impart the necessary fluid pressure to establish and maintain circulation. By a manifold of valves and connections, provision is made so that the pump suction lines may draw cement slurry from a cement mixing device, or fluid from the mud pit serving the well, or water from special measuring tanks. A flexible connection is provided between the pump and the casing head that can readily be broken at the latter point to insert the moving plugs into the upper end of the casing (see Fig. 192).

One of the two plugs moves down through the casing under the influence of pump pressure in advance of the cement slurry, and one behind. Inasmuch as many tons of cement slurry may be used in such

an operation, the two plugs may be hundreds of feet apart as they descend through the casing. Water or drilling fluid must be pumped down through the casing after the second plug in order to provide a noncompressible power-transmission medium necessary in moving the cement column and plugs against the casing and well friction. The two plugs not only serve to prevent contamination and dilution of the cement with other fluid during passage through the casing, but also provide a means of indicating to the operator when all cement has passed out of the casing. The casing is equipped at its lower end with a special cement shoe or baffle collar which retains the two plugs in the bottom of the casing but permits the cement to pass out into the well and up into the annular space between the casing and the wall of the well. When the two plugs come to rest in the lower end of the casing on the baffle collar or in the cement shoe, pump pressure is suddenly increased and the operator knows that all or nearly all of the cement has passed out of the casing. The latter is then lowered to bottom and pressure is held on the fluid in the casing until the cement sets. A back-pressure valve is frequently placed in the cement shoe to prevent cement from finding its way back into the casing in the event that pump pressure declines. After the cement has had time to harden, the plugs, together with the cement shoe, baffles or other barriers in the lower end of the casing, may readily be drilled out with either cable or rotary tools.

Pumping Cement Directly through the Casing without Barriers.—A process used to some extent in the California fields is one similar to the Perkins process described above, except that it is operated without plugs or barriers of any sort to separate the cement from the well fluid. Two factors involved in this method tend to make the results somewhat uncertain: (1) the extent to which the cement may become diluted by admixture with the well fluid and water used in pumping and (2) uncertainty concerning the precise time at which the last of the cement passes out of the casing. Extensive use of the method has shown that admixture with the well fluid is not ordinarily detrimental in casings under 10 in. in diameter. The time of passage of the cement through the casing can be calculated with fair accuracy by measuring the water used in pumping it down, using an amount equivalent in volume to that of the casing. The water so used may be gauged from a tank or through a meter. Most operators prefer to stop the pump while a little cement is still left in the casing, in order to avoid possible dilution of the cement about the casing shoe, though the necessity for this is somewhat doubtful since the greater density of the cement in comparison with that of the well fluid would probably cause it to sink to the bottom after flow of fluid from the casing ceases.

Squeeze Cementing.—Development of the tubing methods of

placing cement about casing in wells has led to the perfection of so-called "squeeze cementing" methods in which the fluid cement slurry, after being placed in the bottom of the well, is subjected to high pump pressure designed to force some of it into the surrounding wall rocks. To facilitate this, the formation is first subjected to high pump pressure with the purpose of driving water into the wall rocks to reduce their resistance to later entrance of the fluid cement. As in the case of the "bottom-packer" tubing method of placing cement, an auxiliary column of tubing is used inside the casing to be cemented. A cement retainer or packer of suitable design closes the space between the tubing and casing at the level of the casing shoe, and is held in position by slips set against the inner wall of the casing to resist pressure from below. Cement is pumped down through the tubing and out into the well, then squeezed by applying high pump pressure with all outlets at the surface closed. Pressure is maintained on the system until the cement takes its initial set. However, the tubing may meanwhile be disengaged from the retainer or packer and withdrawn from the well, leaving the retainer lodged in the lower end of the casing. A back-pressure valve in the retainer permits passage of cement out into the well but prevents its return after the tubing has been disengaged.

Cementing through Perforations.—Instead of forcing cement down through the full length of a column of casing, so that it must pass through or under the casing shoe before entering the annular space, provision may be made so that the cement will pass through holes in the walls of the casing. It may thus be possible to "spot" cement in the annular space outside the casing at any desired point, perhaps far above bottom, without cementing all the intervening space. A smaller amount of cement may be used than is otherwise necessary and it may be placed at lower pump pressure. This method finds many useful applications in well repair work and is especially useful in cementing "combination strings" designed to serve both to confine oil and gas and to exclude water. Cementing through perforations may be conducted either by pumping cement slurry directly through the casing between moving barriers or through a column of auxiliary tubing.

In cementing through perforations with the aid of an auxiliary string of tubing, perforations are provided in the wall of the casing at the level where it is desired to place the cement. After the casing is in place in the well and circulation of well fluid has been obtained, a bridging plug or packer or retainer is set in the casing just below the perforations and the column of auxiliary tubing is lowered with a cement retainer or packer containing a back-pressure valve on its lower end. The retainer or packer is set against the inner wall of the casing just above the perforated section. Cement slurry is then forced down through the tubing

and out through the perforations into the annular space. The tubing is then disengaged from the retainer, leaving the latter in the well. After the cement has set and hardened, the retainer and lower bridging plug and intervening cement can readily be drilled out of the casing.

Variations of the ordinary method of cementing through perforations are known as "full-hole" cementing and "multiple-stage" cementing—patented methods controlled by the Halliburton Oil Well Cementing Co. Full-hole cementing is conducted with the aid of a device, consisting of a short perforated collar containing a back-pressure valve and a sliding sleeve, which closes the cement ports in the collar as the column of casing is lowered into the well, at the same time circulating fluid down through the casing and back to the surface. Cement is then pumped down through the casing between two moving plugs. The lower plug is so designed that it moves the sliding sleeve downward, opening the cement ports in the collar, through which the cement slurry is forced out into the annular space. The lower plug comes to rest on the back-pressure valve and prevents cement from passing down into the casing below this point. The upper plug ultimately comes to rest on the lower plug and again closes the ports in the perforated collar. The plugs and back-pressure device are readily drilled out of the casing after the cement has set and hardened.

The same principle of a sliding sleeve, actuated by the cement plugs uncovering ports in a perforated collar, is utilized in "multistage" cementing. By slight differences in the design of the plugs, it may be arranged so that the first plug moving down the casing does not actuate the sliding sleeve on the perforated collar. A first batch of cement thus moves down past the perforated collar and is discharged under the shoe of the column of casing in the conventional way. When this has set and hardened, a second batch of cement is forced down between a second pair of plugs, the lowermost of which is designed to actuate the sliding sleeve and causes the cement to be forced out into the annular space through the perforated collar. By using casings of progressively smaller diameter toward the lower end of a column of pipe and accurately fitted plugs, cement may be forced out through several perforated collars in successive batches, each at a different depth.

Exclusion of Bottom Waters

If a well has been drilled through an oil-producing formation and has encountered bottom water, or if a portion of a productive zone yields edge water in excessive amount, it will be advisable to exclude the water-yielding strata by plugging the lower portion of the well. Occasionally bottom water will find access to a well through cavities and crevices resulting from the use of explosives to stimulate production. A some-

what similar operation must be conducted in abandoning the lower portion of a well in order to produce from an upper horizon, or in redrilling a well when it has departed from the vertical or the walls have caved. For such purposes, various types of plugs are applied, plugs composed of cement being preferable in most cases. Chemical plugging and mudding methods are also effective.

Plugging Wells with Cement.—Cement used as a plugging medium in excluding bottom water from wells is usually placed in the bottom of the well as a neat cement slurry and allowed to set and harden. The cement may be placed on bottom without excessive dilution or contamination with the well fluid, by means of a dump bailer; or, if a large amount of cement is involved or high pump pressure must be used to prevent flow of fluids into and from the well, the fluid cement may be forced to bottom through an auxiliary string of tubing inside the casing.

If the upward pressure developed by bottom water against the plug is likely to be high, as in cases where a strong flow of high-pressure water must be dealt with, it is a good plan to drill entirely through the bottom-water zone, starting the plug in a lower stratum where it may obtain a formation lock that will better resist the pressure. Or the hole may be under-reamed at the point where the plug is to be placed, thus developing a shoulder against which the cement plug may bear. Still another method for locally enlarging the bore of the well to afford an anchor for a cement plug is to detonate a small charge of explosive at the point where the plug is to be placed.

"Equalizing" Cement through Tubing.—In placing cement slurry in the bottom of a well through a column of tubing or drill pipe, the tubing is lowered to a point just off bottom and circulation of well fluid is established and maintained until all accumulated clay and detrital material have been removed and the well fluid is of uniform density. The necessary amount of cement to form the desired plug is then pumped down through the tubing, followed by fluid of the same density as that in the well. The upper ends of the tubing and casing are both opened to the atmosphere to permit the cement slurry to equalize or attain the same level outside as inside the tubing. The tubing is then raised to the level selected for the top of the finished plug and excess cement in the well and tubing above this point is circulated back to the surface by reverse circulation. The tubing is then raised farther so that it is entirely free of the cement and the plug left undisturbed to set and harden.

Plugging by the Displacement Method.—In this method, the requisite amount of cement slurry is pumped down to the bottom of the well through a column of tubing or drill pipe suspended with its lower end just off bottom. A measured amount of water or drilling fluid, just

sufficient to displace the cement from the tubing, is pumped down after the cement, leaving some cement in the lower end of the casing so that when it is raised to free it of the cement plug, the latter will not be diluted with water from the tubing. The columns of cement inside and outside of the tubing should be slightly unbalanced with the excess in the tubing, thus preventing backflow of cement from the well into the tubing when pumping is stopped and the tubing is opened to the atmosphere at the surface.

Moving Plug Method of Displacing Cement from Tubing.—Some operators prefer a more positive means of determining when all cement has been displaced from the tubing. With this purpose, a special foot piece is placed on the lower end of the column of tubing and a special cement plug is pumped down the tubing after the cement. When the cement plug comes to rest in the foot piece on the lower end of the tubing, pressure increases, stalling the pumps, and the operator knows that all cement is out of the tubing. The latter is then raised to the level desired for the top of the cement plug and circulating fluid is pumped down through the annular space from the surface. Reversed circulation forces the cement plug and excess cement back to the surface through the tubing, a special capsule being provided in the tubing head to receive and retain the plug on its return to the surface without interfering with the flow of cement that follows it. The tubing is then raised and the cement in the bottom of the well allowed to set and harden.

Squeeze Method of Cement Plugging.—This method contemplates applying high pump pressure to the cement slurry after it reaches the bottom of the well, in the hope of forcing some of it to enter crevices or permeable formations through which water enters. A column of tubing is suspended in the well with the lower end a short distance off bottom. Direct circulation down through the tubing is established and maintained until fluid throughout the system is uniform in density. The cement slurry is then pumped down through the tubing and, as the first of the cement emerges from the tubing, the outlet from the annular space between the tubing and the casing at the surface is closed and the maximum possible pump pressure is applied at the upper end of the tubing. If liquid cement enters the formation, more fluid is pumped down through the tubing to maintain pressure. This continues until the safe limit of pressure is reached or until nearly all of the cement is displaced from the tubing. Pump pressure is then released, the tubing raised to the level desired for the top of the cement plug and excess cement washed back to the surface by reverse circulation. The tubing is then raised so that it is free of the cement in the bottom of the well, surface outlets are closed and pump pressure is maintained on the system until the cement has set. If there is danger of backflow after squeezing the

cement into the formation, a stuffing-box type of casing head may be used so that the tubing may be raised without releasing pressure on the well.

Types of Plugs for Controlling Bottom Water.—If water entering from strata exposed in or near the bottom of a well is under high pressure, the upward force of water may make it impossible to hold cement slurry in the bottom of the well until it sets and hardens; or perhaps water flowing up through the cement will so agitate and dilute it that it does not set properly; or channels may be developed through or about the cement which render it ineffective. In such cases, it is necessary to bridge or plug the bottom of the well with some solid material to provide a support for the cement,

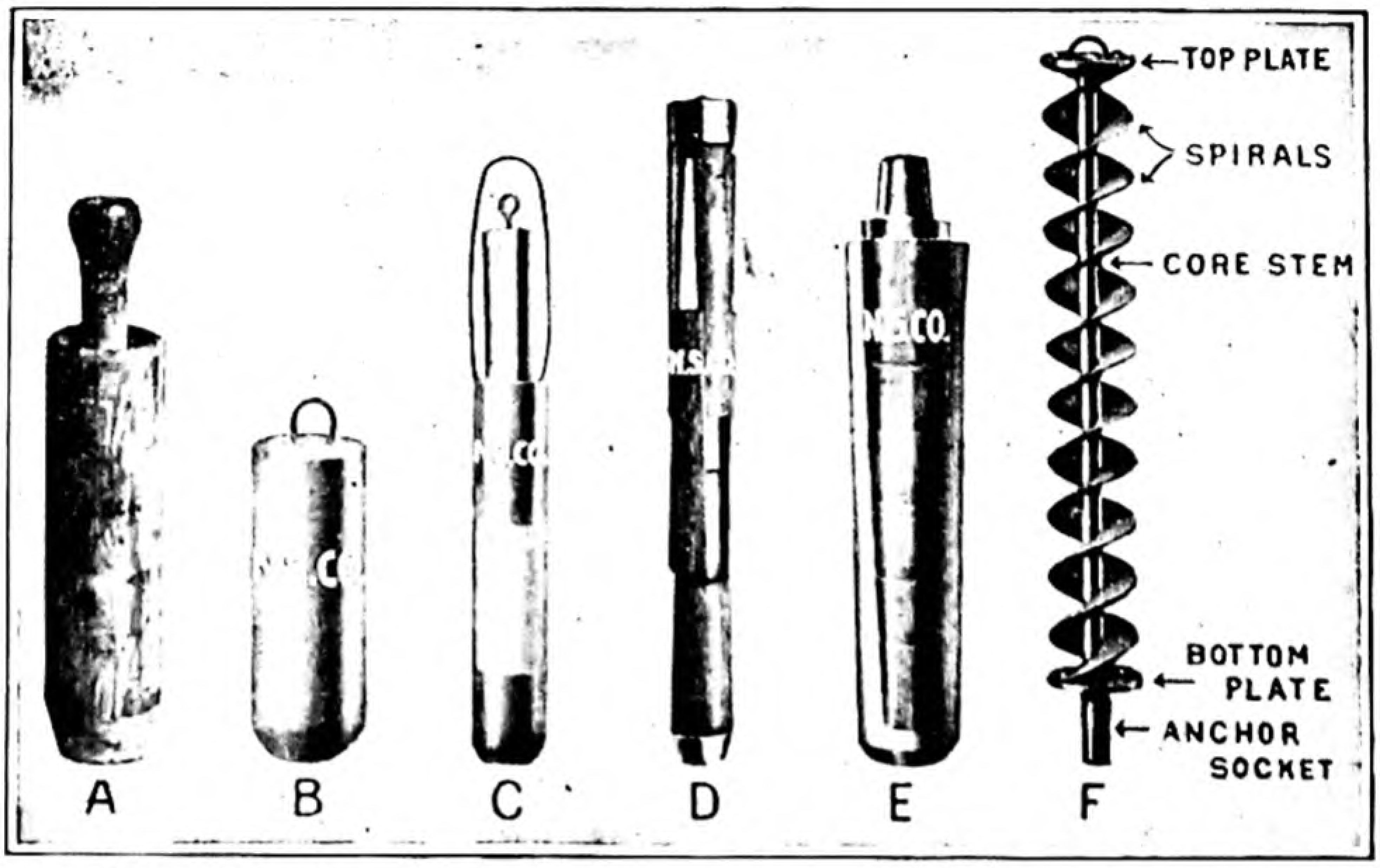


FIG. 181.—Types of plugs. *A*, common wooden plug; *B*, lead plug; *C*, lead and rubber plug with mandrel; *D*, limit plug; *E*, wood and rubber plug; *F*, Guiberson-Crowell bottom-water plug.

and to protect it from disturbance by upward-flowing water until it can attain its initial set.

Bundles of strands from annealed wire cables, cut in short lengths, with hemp or manila fiber unraveled from old rope, can be rammed into a compact mass in the bottom of the well with cable-drilling tools, partly controlling flowing water and serving as a foundation for a cement plug. Lead wool placed in the well in small bundles, also, has been used effectively in plugging off bottom water and preparing a foundation for a cement plug. Various forms of wooden, lead or cast-iron plugs are also available for this purpose (see Fig. 181). Some of these have parts designed to telescope longitudinally, causing lateral expansion of the outer members so that they may be wedged securely against the wall of the well and may not be easily displaced by upward pressure.

The Guiberson-Crowell plug, a useful device for plugging off bottom water, consists of a pair of heavy spiral springs wrapped about a metal mandrel and maintained under tension while being inserted in the well, by a dowel pin driven through the mandrel (see Fig. 181*F*). Oakum saturated with melted pitch, tar or cement is packed in the spaces between the spirals of the spring, this material being held in position by small wires. An anchor pipe of sufficient length to hold the plug somewhat above bottom is screwed to the lower end of the supporting mandrel. The plug with its anchor is lowered to the bottom of the well in extended position, suspended from the lower end of a string of cable drilling tools. When in place, a few blows with the

tools break the wooden dowel; the mandrel falls through the springs into the anchor pipe, allowing the springs to collapse and expand laterally, pressing against the walls of the well and compressing the oakum between them. A little neat cement placed in the bottom of the hole with the bailer before lowering the plug, so that the latter will be immersed in the liquid cement, further ensures success of the work.

Chemical Methods of Water Exclusion

Low-pressure waters may be excluded from wells by treatment of the water-yielding strata with chemical reagents that react with saline ground water to form precipitates that adhere to the rock surfaces and fill the rock pores so that fluids may not readily pass through them. Antimony trichloride in oil solution forms an abundant precipitate of antimony oxychloride on contact with water. This reagent is also soluble in water in concentrated form but, on dilution of the concentrated solution, the oxychloride is precipitated. Silicon tetrachloride in oil solution also reacts with water to form a precipitate of silicic acid, an effective cementing material. Sodium silicate and sodium carbonate solutions, on contact with saline ground waters, form precipitates that may be effective in closing rock pores. Super-fatted soaps, colloidal solutions and finely divided cements made up in nonaqueous solutions may also be used to close the pores of a water-yielding formation. On dilution or contact with salt water, these substances may, under favorable conditions, form abundant precipitates.[12,15]

Water solutions of sodium silicate and ammonium bicarbonate in appropriate concentrations have low viscosities when first prepared but, after a few hours, silicon hydroxide or silicic acid begins to form as a sol or colloidal solution, with a water solution of sodium carbonate and ammonium hydroxide as the liquid phase. As this colloidal solution forms, the viscosity increases rapidly until it becomes semisolid. After further standing it becomes an elastic gel of high molecular weight, then becomes more rigid and increasingly hard and nonelastic. The liquid phase remains in the structure of the solid mass, either combined or absorbed. A solution containing 50 per cent of 18 per cent sodium silicate, 15 per cent of 12 per cent ammonium bicarbonate and 35 per cent of water at a temperature of 100°F. will set in about 60 min. Squeezed under pump pressure into a porous formation encountered in a well, through a suitable system of tubing and packers so arranged as to confine the solution to the interval to be treated, the solution later solidifies and effectively plugs the formation. As a result, movement of fluids into the well through this interval is greatly diminished or even entirely prevented. This method of chemical plugging of formations, developed by Dowell, Inc., has been successfully used not only for excluding water but also for sealing off high gas-oil ratio formations to conserve gas. It is to be noted that this process is nonselective, in that it will function in

any porous and permeable formation and does not require the presence of salt water in the formations treated. The plug formed is permanent in character and is capable of withstanding high differential pressures. A chemical charge of 1,000 gal. costs about \$300.

A mixture of oxides of aluminum, silica, iron, magnesium and lead, with a little portland cement and bentonite, has been effectively used as a plugging agent as a means of selectively excluding water in a formation producing both oil and water. This material will not set in the presence of oil but does so if oil is absent. The entire interval is "cemented," but the material opposite the oil-bearing part of the formation remains in a semiliquid condition and can be washed out of the well after the remaining material opposite the water-yielding strata has set and hardened.

Plastics such as bakelite have also been effectively used in excluding water from wells. Applied in molten condition at elevated temperature, some plastics quickly set to form a permanent, impervious barrier. They are, however, too expensive for general use in competition with portland cement, and have been employed only in situations where comparatively small amounts are required.[6,9,16,20]

It has also been suggested that naphthalene vapor might be used as a plugging agent in porous formations. Naphthalene has a boiling point of 424°F. and melts at 176°F. and would thus solidify in most shallow or moderately deep-seated formations.

Use of Hydraulic Lime in Excluding Water from Wells.—Occasionally it will be necessary to cement a well against the pressure of a strong flow of high-pressure water or gas. Perhaps there is only one string of casing in the well and it is impossible to confine it or to apply pump pressure. It may happen that mudding to "kill" the pressure is ineffective because the formation absorbs the well fluid and makes it impossible to secure circulation. In such a case the operator may resort to the use of hydraulic lime as a means of sealing the walls and excluding the high-pressure gas and water, so that portland cement later introduced may rest undisturbed during its setting period.[25]

Hydraulic lime is manufactured by burning and hydrating lime rock, but the material is not sintered as in the case of portland cement. The calcium and magnesium are left in the hydrated form as $Ca(OH)_2$ or $Mg(OH)_2$ but contain no water of crystallization. Unlike ordinary lime, hydraulic lime will set under water.

When hydraulic lime comes into contact with finely divided silica and the aluminum silicates of shales and clays, it reacts to form complex gelatinous silicates which expand in hardening and fill the rock pores. By forcing it under pressure into a well, we thus convert the mud, which lines the rock walls, into a hard impervious sheathing, locked to the walls

by penetration into rock pores and crevices in such a way as effectively to resist passage of fluids into the well.

In the practical application of hydraulic lime in excluding flowing water and preparing the well for a plug of portland cement, the lime is mixed separately with water and pumped into the well ahead of the cement. The cement follows immediately behind the lime solution which combines with the clay to form a gelatinous adherent coating on the walls of the well so that they present a well-consolidated surface to the cement. As a result, there is little tendency for the clay in the walls to dilute the cement, and the conditions for setting of the cement without agitation by high-pressure flowing water or gas are more favorable.

Hydraulic lime may also be used effectively in rotary drilling by admixture with the mud-laden fluid, in sealing dry or low-pressure sands which absorb the well fluid to such a degree that circulation is difficult or impossible.

Exclusion of Water from Wells by Mudding

The action of circulating mud-laden fluid under pressure in closing the pores of permeable, water-yielding formations has been discussed in a previous section in connection with rotary drilling. In the development of certain California fields, where upper oil and gas strata are cased off behind a water string to obtain production from more productive lower zones, it has become the custom for operators thoroughly to mud the upper formations under pressure in order to prevent intermingling of fluids from different strata above the shutoff. This practice saves one or more strings of casing that must otherwise be cemented between the several zones and gives ample protection to operators producing from the upper beds. Many hundreds of wells have been so treated in the California fields and the records of the State Oil & Gas Supervisor's department show that in more than 85 per cent of the wells the mudding has apparently accomplished its purpose.

The mudding process may be conducted through casing or rotary drill pipe by continued circulation as in rotary drilling; or by using a circulating head and throttling the outlet, an additional pump pressure of many hundreds of pounds may be held on the well while the fluid is circulated. Circulation is usually down through the casing or drill pipe and back to the surface between the pipe and the walls of the well; in some cases it has been found advantageous to reverse the direction, pumping down through the annular space between the conductor string and the inner pipe.

Some operators recommend mudding under a pump pressure of from 200 to 300 lb. per sq. in., continuing circulation until the formation

absorbs less than 2 bbl. of fluid per hour. This is not always possible, though in many cases the volume of fluid absorbed has been reduced to less than 1 bbl. per hr. This condition is often reached after 10 hr. of continual circulation under pressure, but in extreme cases it may require a week or more. It should be pointed out in this connection that the quantity of fluid absorbed by the formation will vary with the wall area exposed, that is, with the depth or thickness of exposed rock face and the diameter of the well. Absorption and the degree of penetration obtained will also vary with the permeability of the beds penetrated and with the pressure of the fluids stored within them.

More effective water exclusion by the mudding method may be secured by the addition of colloidal materials such as Aquagel or Impermex (see pages 297 and 299) or of substances which serve as coagulants for the clay particles. For example, hydraulic lime may be used effectively for this purpose, forming a sticky, pasty clay that rapidly clogs all rock fractures and crevices.

In cases where oil and gas sands have been mudded off behind the water string at some distance above the cement plug, mud is sometimes pumped down between the conductor pipe and the water string until the formation no longer absorbs fluid. The space behind the water string is thus left filled with heavy mud which effectively prevents intercommunication of fluids between the strata penetrated. Wells so mudded have maintained the same fluid level behind the water string for years, proving conclusively the effectiveness of the process.

EQUIPMENT USED TO FACILITATE CEMENTING OF CASING IN WELLS

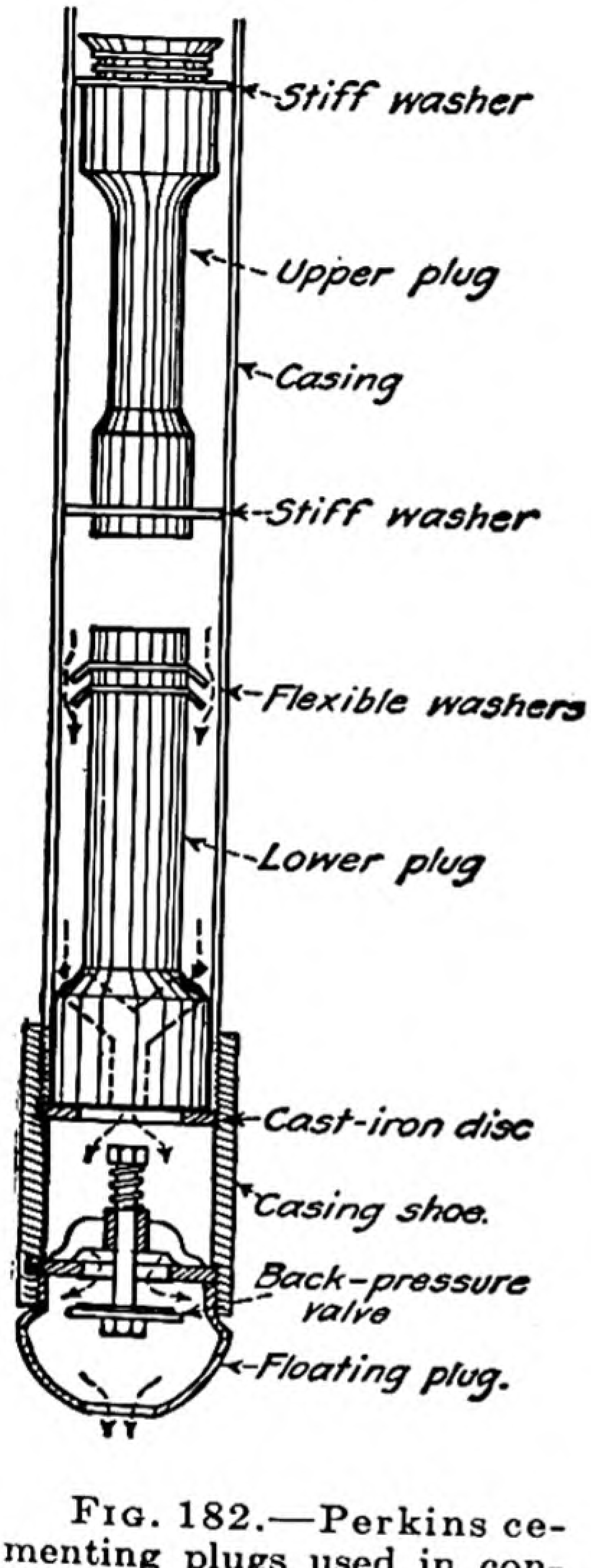
A variety of different appliances designed to facilitate cementing operations are available from equipment manufacturers and service organizations specializing in this kind of work.

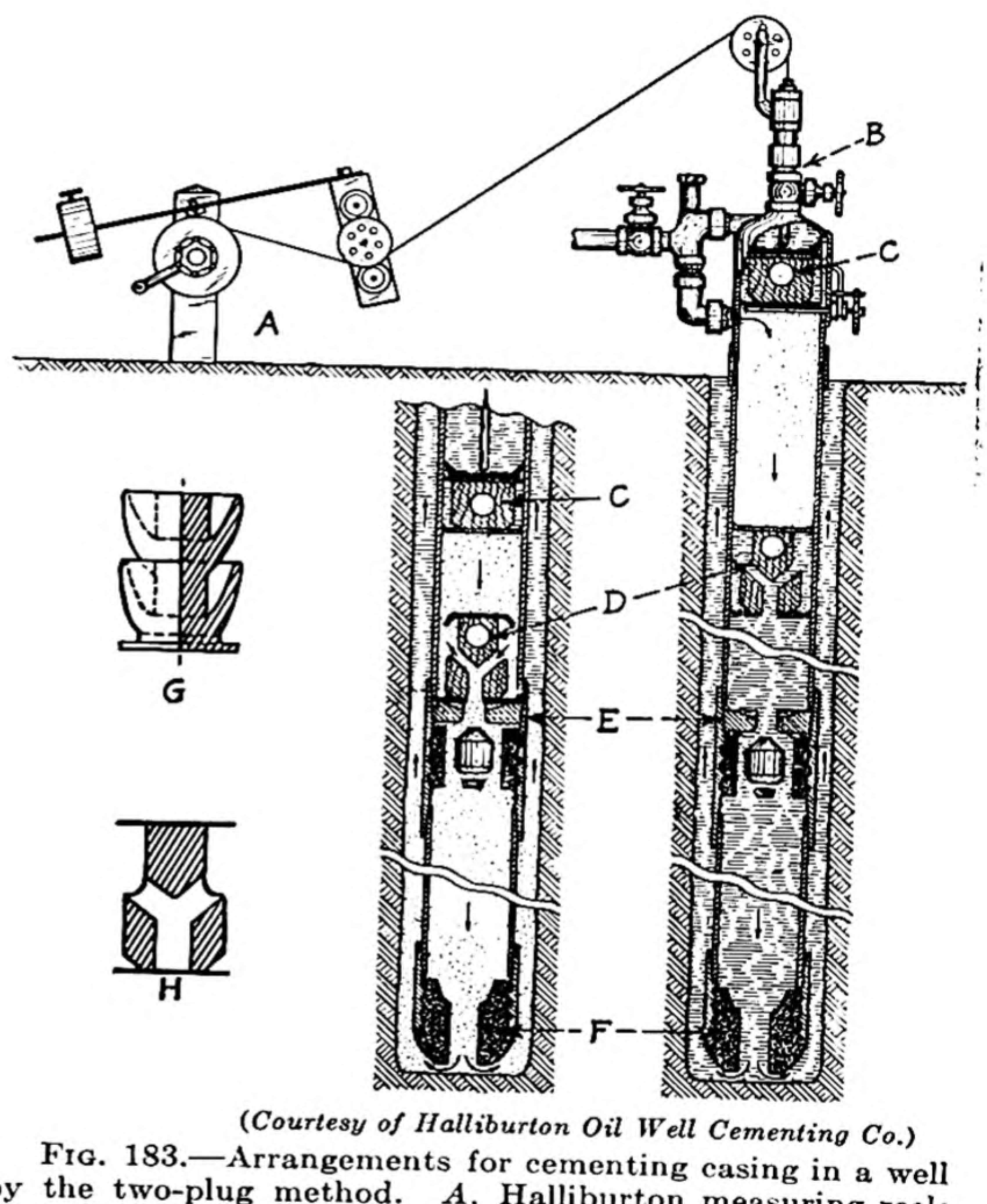
Cementing Plugs.—The plugs, used in the conventional method of pumping cement through casing between moving barriers, are usually made of wood turned or shaped to accurate dimensions and equipped with rubber, leather or fabric disk or cup-shaped washers. Figures 182 and 183 picture several different forms of cement plugs used by the Halliburton Oil Well Cementing Co., and Perkins Cementing, Inc., each designed to meet the requirements of a particular operation or situation.

Cement Shoes and Collars.—The casing shoe, used primarily to strengthen and protect the lower end of the column of casing against distortion and wear, may also play an important role in providing a means of limiting downward movement of the cementing plugs, so that they do not fall out of the casing. A commonly used type of casing shoe is partly closed with a neat cement plug, rounded on its lower end to guide the casing down the hole. This is designed to be attached to the lower end of a column of casing to be cemented in a well by the two-plug method. The lowermost moving plug comes to rest on the cement barrier in the shoe, but the cement slurry passes out through the cylindrical hole in the center of the cement plug, until the upper nonflexible moving plug comes to rest on top of the lower plug and closes

the outlet. After the cement slurry has set, the wooden plugs and washers and the cement barrier plug in the shoe are readily drilled out.

Figure 184 illustrates a type of cement baffle collar designed to be placed between two joints of casing instead of an ordinary casing collar, a joint or two above the lower end of a column of casing to be cemented in a well. The cement baffle is designed to stop and support the moving plugs used in a cementing operation in the same way as the cement guide shoe described in the preceding paragraph.





(*Courtesy of Halliburton Oil Well Cementing Co.*)

FIG. 182.—Perkins cementing plugs used in connection with floating plug and back-pressure valve.

FIG. 183.—Arrangements for cementing casing in a well by the two-plug method. *A*, Halliburton measuring reel; *B*, cement head assembly; *C*, upper plug; *D*, lower plug; *E*, baffle collar and valve; *F*, cementing shoe; *G*, rubber upper plug; *H*, wooden lower plug.

Figures 185 and 187 picture solid cement baffles in casing shoes and collars intended for use in situations where cement slurry is to be discharged through perforations within the baffle.

In a previous section (see page 403) the advantages of floating in a long column of heavy casing are discussed. To facilitate this and also the subsequent cementing operation, a cement float shoe may be used. This combines the features of the common form of cement guide shoe to support the wooden cementing plugs during the cementing operation, and an upward-seating float valve to close the lower end of the casing against the well fluid while the casing is being lowered into the well. Figure 158 (page 403) presents a sectional view of a type of cement float shoe manu-

factured by the Baker Oil Tools Co. The bakelite valve and cage and rubber seat are readily drilled out along with the cement baffle when the cementing operation is completed. Similar features are incorporated in the Baker cement float collar pictured in Fig. 186. This is intended to be placed in the casing column a joint or two above the shoe when casing is being cemented under circumstances that may make it desirable to leave some of the cement inside of the casing.

(Courtesy of Halliburton Oil Well Cementing Co.)
FIG. 184.—Cementing baffle collar.

At times, in cementing a long column of casing, detrital material may accumulate under the cement shoe to such an extent that it impedes free movement of the cement slurry or causes it to channel along one side of the pipe. The better to distribute the cement about the casing and also more effectively to clear away accumulations of clay on the walls of the well during insertion of the casing and during the process of circulating prior to cementing, the Baker cement whirler float shoe has been designed. Fluid is discharged from this shoe at a downward angle as well as through a restricted central passage (see Fig. 185). The resulting jetting action is effective both in cleaning away detrital material and in developing a swirling, helical motion of the cement that assists in securing better distribution of cement about the casing and offsetting channeling tendencies. The side-discharge whirler principle is also built into the Baker cement whirler float collar (see Fig. 187). Another variety of whirler shoe has the side baffles so arranged that the fluid ejected through them is directed upward instead of downward.

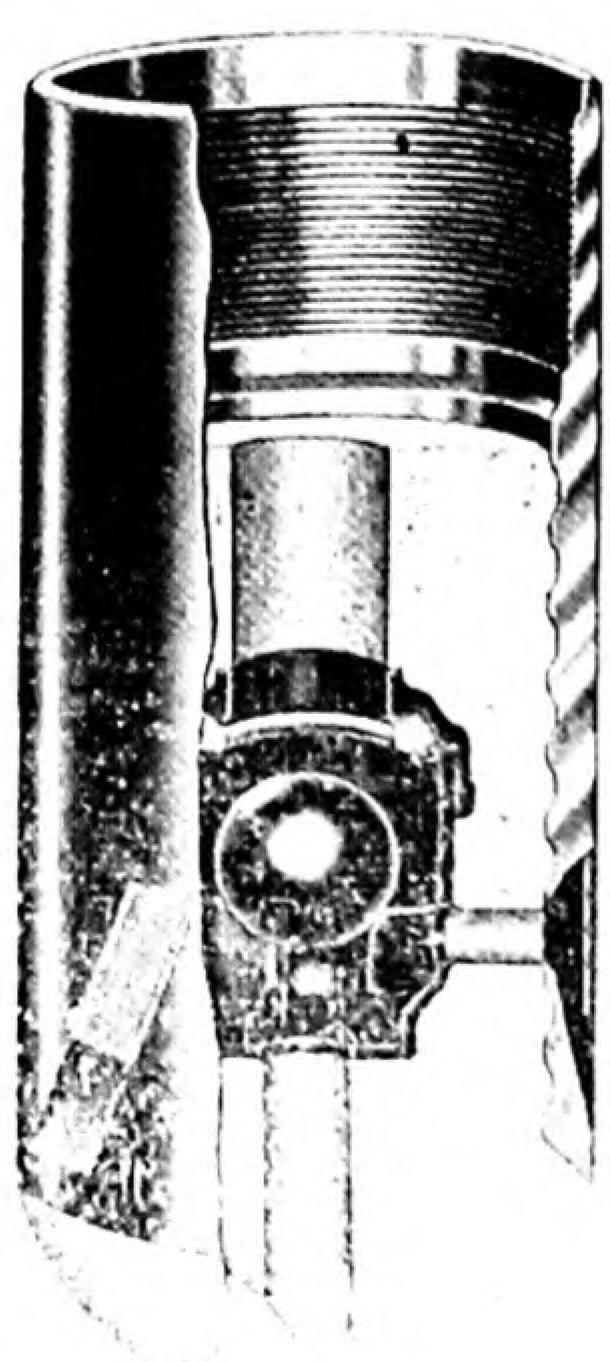


FIG. 185.—Whirler float shoe.

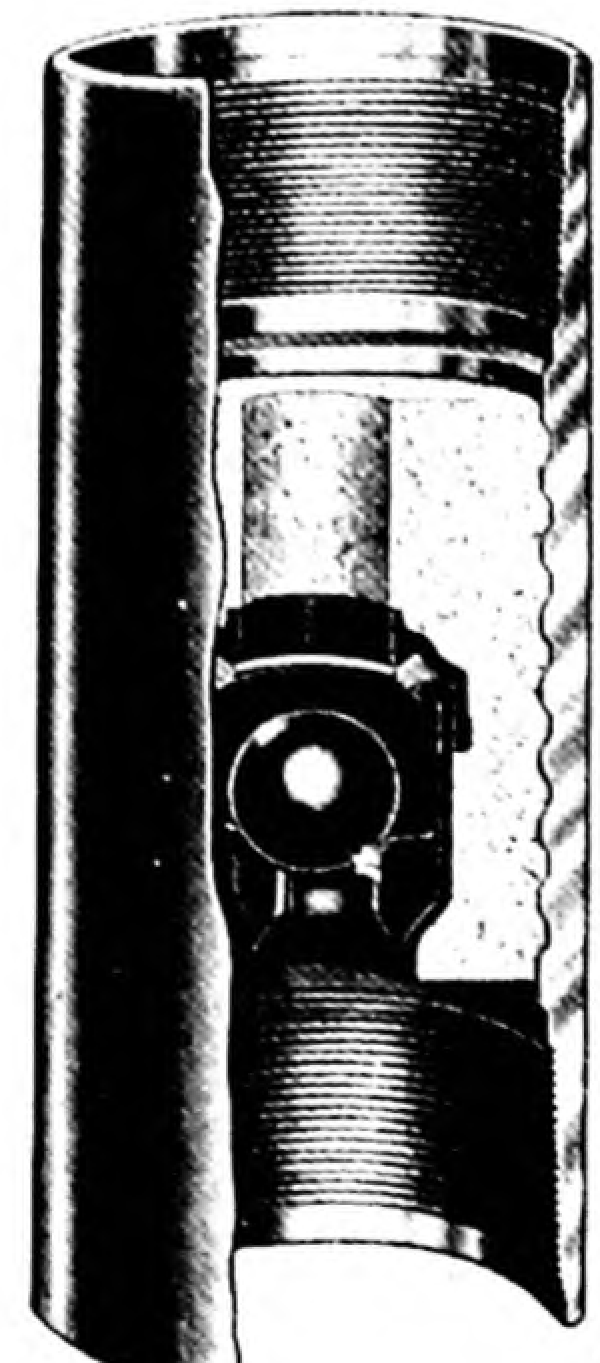
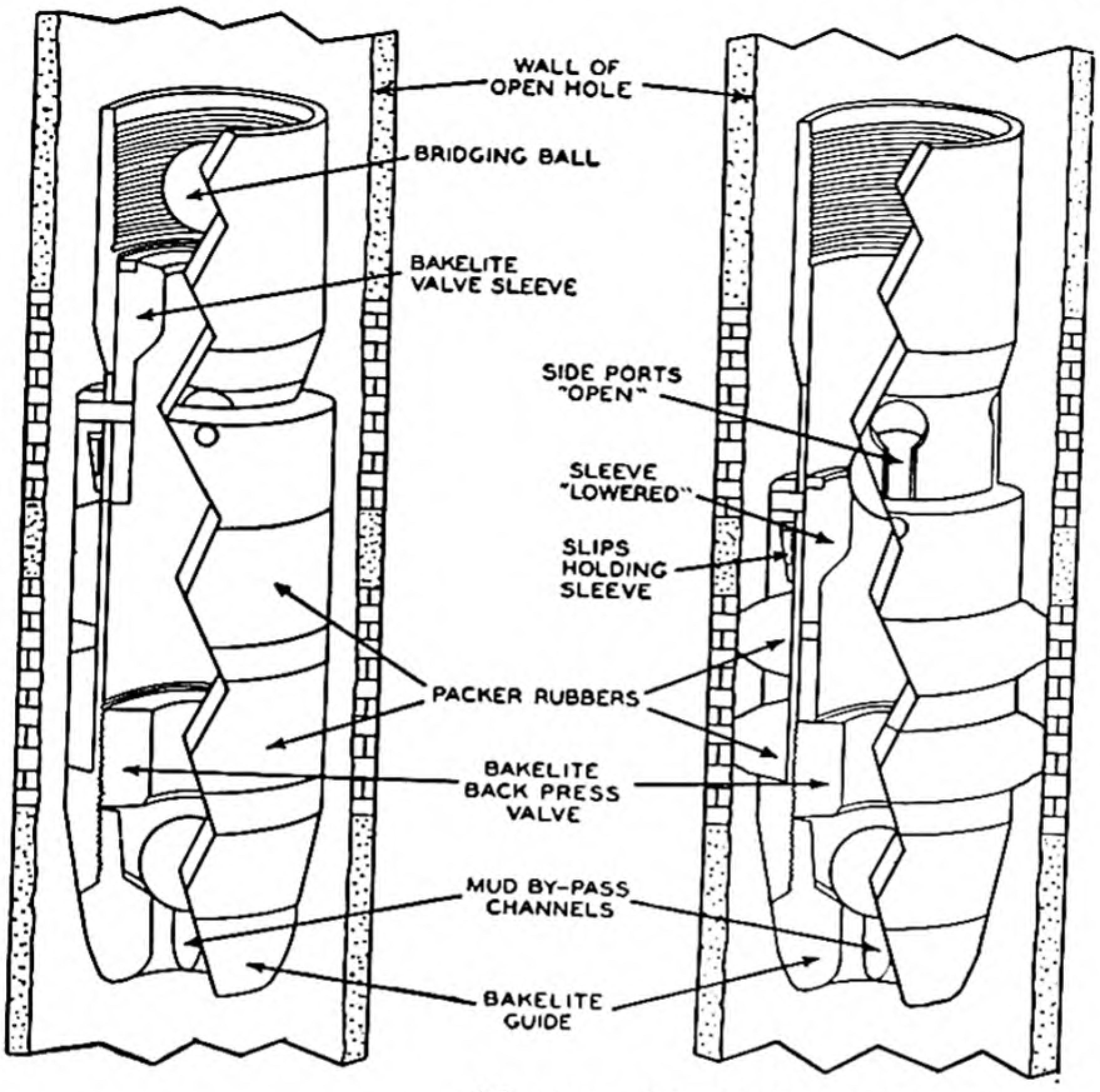


FIG. 186.—Cement float collar.

(Courtesy of Baker Oil Tools, Inc.)
FIG. 187.—Cement float collar.

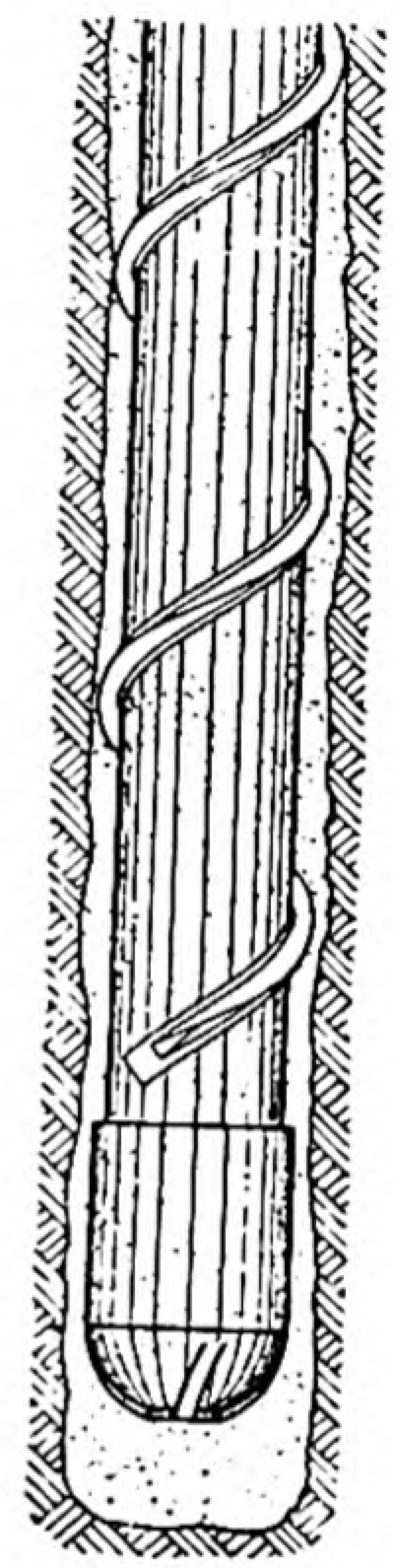
In cementing a casing in an open hole, it is sometimes desired to suspend the casing some distance off bottom, to cement it against the wall of the well and to prevent

access of the cement into the lower part of the well below the casing shoe. For this purpose, the Larkin Cementrol shoe may conveniently be used (see Fig. 188). This is equipped with a rubber packer that can be expanded to close the space between the shoe and the wall of the well. A bridging ball pumped down the casing ahead of the cement actuates a sliding sleeve that expands the packer and opens the side discharge ports in the shoe above the packer through which the cement passes into the annular



(Courtesy of Larkin Packer Co., Inc.)

Fig. 188.—Method of application of the Larkin Cementrol casing cementing shoe. Left: before expanding packer against wall of well. Right: packer expanded and side discharge ports open to pass cement slurry into annular space.



(Courtesy of Halliburton Oil Well Cementing Co.)

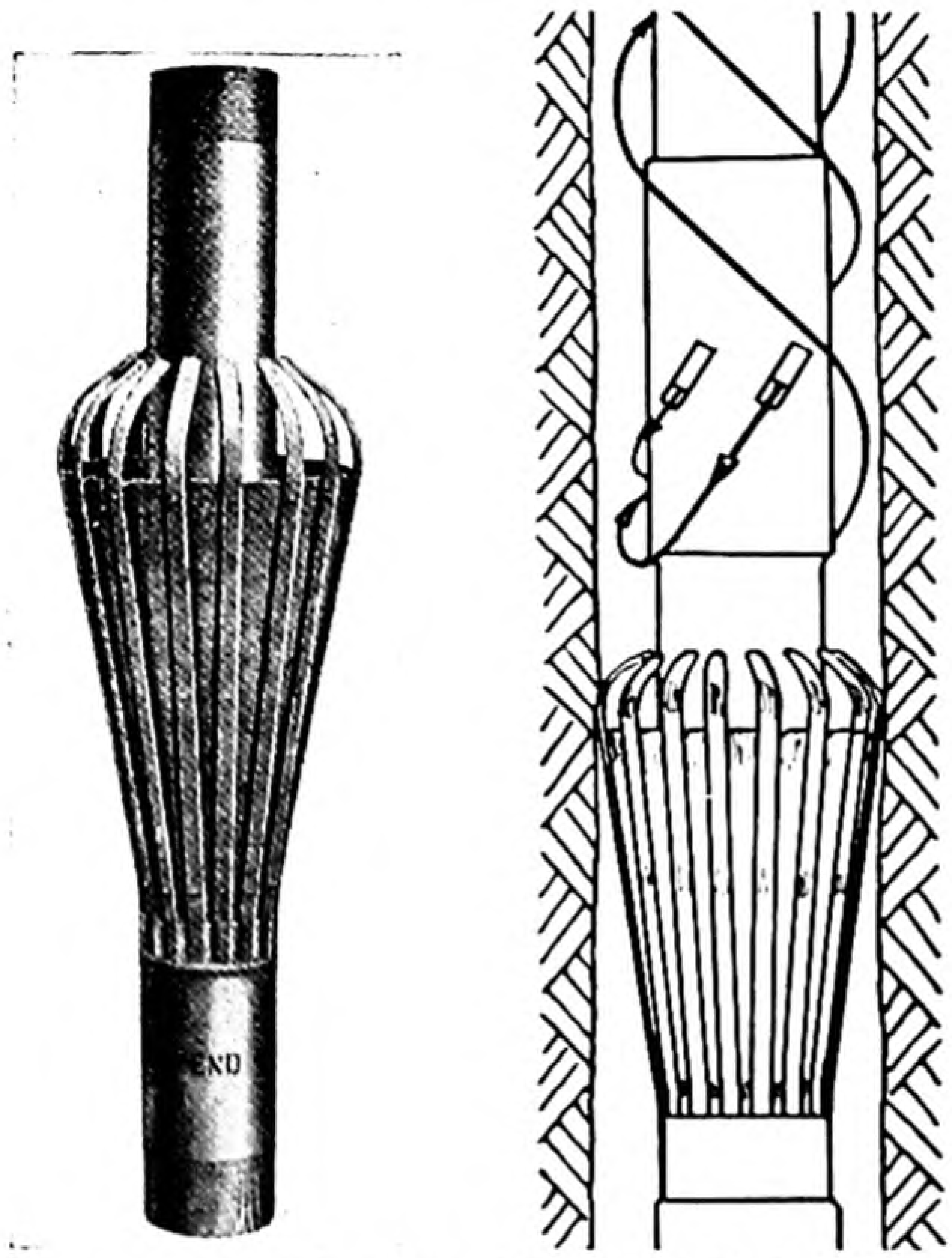
Fig. 189.—Coaxial spiral.

space. The bridging ball and bakelite mechanism within the shoe are readily drilled out after the cement has set.

The Coaxial Spiral.—Another device designed to assist in securing better distribution of cement slurry about the casing and to oppose channeling tendencies is the Halliburton Oil Well Cementing Company's "coaxial spiral." This consists of a long triangular section of rubber vulcanized to a steel strap base (see Fig. 189). This base is welded to the outside of the casing in the form of a helix at points where cement is to be distributed. It is installed at an angle that makes it self-cleaning as the pipe is lowered into the well. Being composed of flexible rubber, the spiral yields to wall pressure and does not cut into the walls of the well. In addition to assisting in distributing cement slurry about the casing, the spiral is also effective in centering the casing in the well so that there is space all about it in which cement may accumulate.

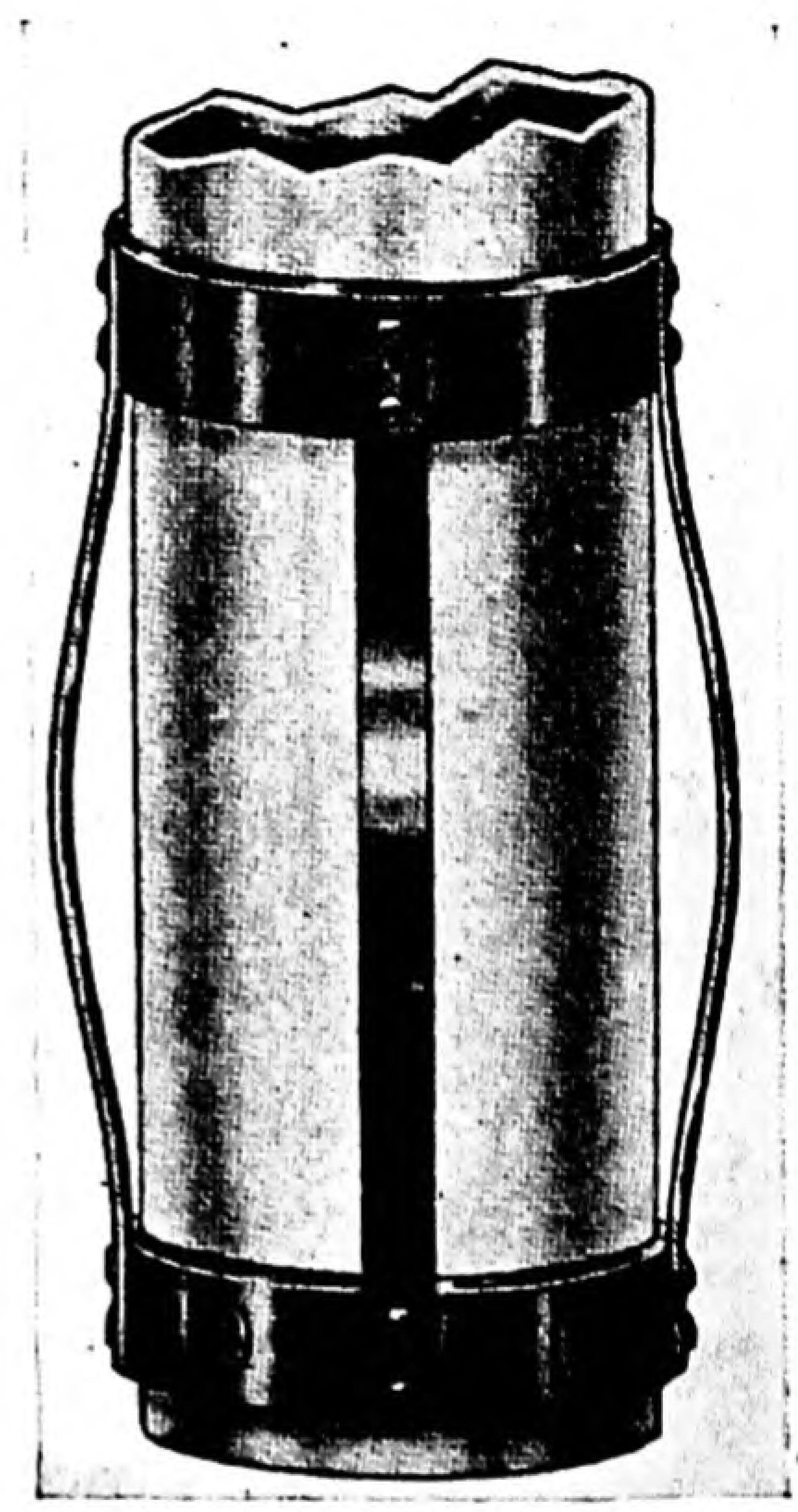
Cementing Baskets.—A cementing basket is a device designed to be attached to the outside of a column of casing to close the annular space between the wall of the well and the casing, in such a way as to prevent cement slurry from moving past the

basket and to direct its flow in the opposite direction. Figure 190 illustrates a type of basket constructed of overlapping flexible sheet-brass "petals" mounted on steel reinforcing ribs. In more primitive designs, the basket is of heavy canvas supported by steel ribs. The reinforcing ribs are attached to a steel collar that is coupled into or welded on the casing column at the proper point. When the casing column is being lowered into the well, the upward force of the fluid tends to collapse the petals against the pipe. However, as soon as the casing comes to rest and a little fluid pressure is applied above, the petals expand to contact the wall of the well and close the annular space. Cement slurry discharged through perforations within or above the basket



(Courtesy of Baker Oil Tools, Inc.)

FIG. 190.—Basket used in well cementing operations. Right: use in conjunction with whirler float collar.



(Courtesy of Larkin Packer Co.)

FIG. 191.—Casing centralizer.

is thus confined to the annular space above the basket and may not move downward to contaminate the formation below. A basket may also be used in an inverted position to prevent cement slurry from passing upward through the annular space beyond the point where the basket is attached. A basket is also used on a column of casing to prevent cement slurry, in process of placement behind the casing, from being contaminated with wall cavings from overlying formations, and assists in confining the cement to a particular interval within the annular space.

Casing Centralizers.—It is highly desirable that the lower end of a column of casing to be cemented in a well be concentric with the wall of the well, so that the cement, when placed in the annular space, will be of uniform thickness about it. To assure this, a casing centralizer may be used. This consists of a series of curved metal springs bearing against the wall of the well and attached at either end to a collar welded to the outside of the pipe, as illustrated in Fig. 191.

Cleaning the Walls of the Well of Deposited Clay to Secure Better Bond with the Cement.—The sheath of clay deposited on the wall of the well by the circulating fluid

in a rotary-drilled well should be removed, if possible, from the interval in which the cement is to be placed. Much of the clay may be washed out by circulating water or thin mud through the well before the cement is placed, but if the mud cake is thick and well compacted, it will be necessary to resort to mechanical methods of dislodging it. The Baker rotary hydraulic expansion wall scraper, described on page 564, may be used for this purpose or the B. & W. wall cleaning guides, described on page 564.

Cement Wash-pipe Lining.—If a column of screen pipe or a liner containing sections of screen pipe is to be cemented in a well. it will ordinarily be impossible to secure circulation of fluid down through the pipe to the bottom because of the tendency of the fluid to escape through the screen pipe to the annular space. Where positive circulation is required for washing or cementing operations, the screen pipe may be given a thin coating of neat cement on the inner surface that can readily be drilled out after the liner is in place and cemented, leaving the perforations free for oil or gas production. The Halliburton Oil Well Cementing Co. places cement lining inside of screen pipe in specially equipped field shops, using a protective material that prevents the cement from entering the screen-pipe perforations.

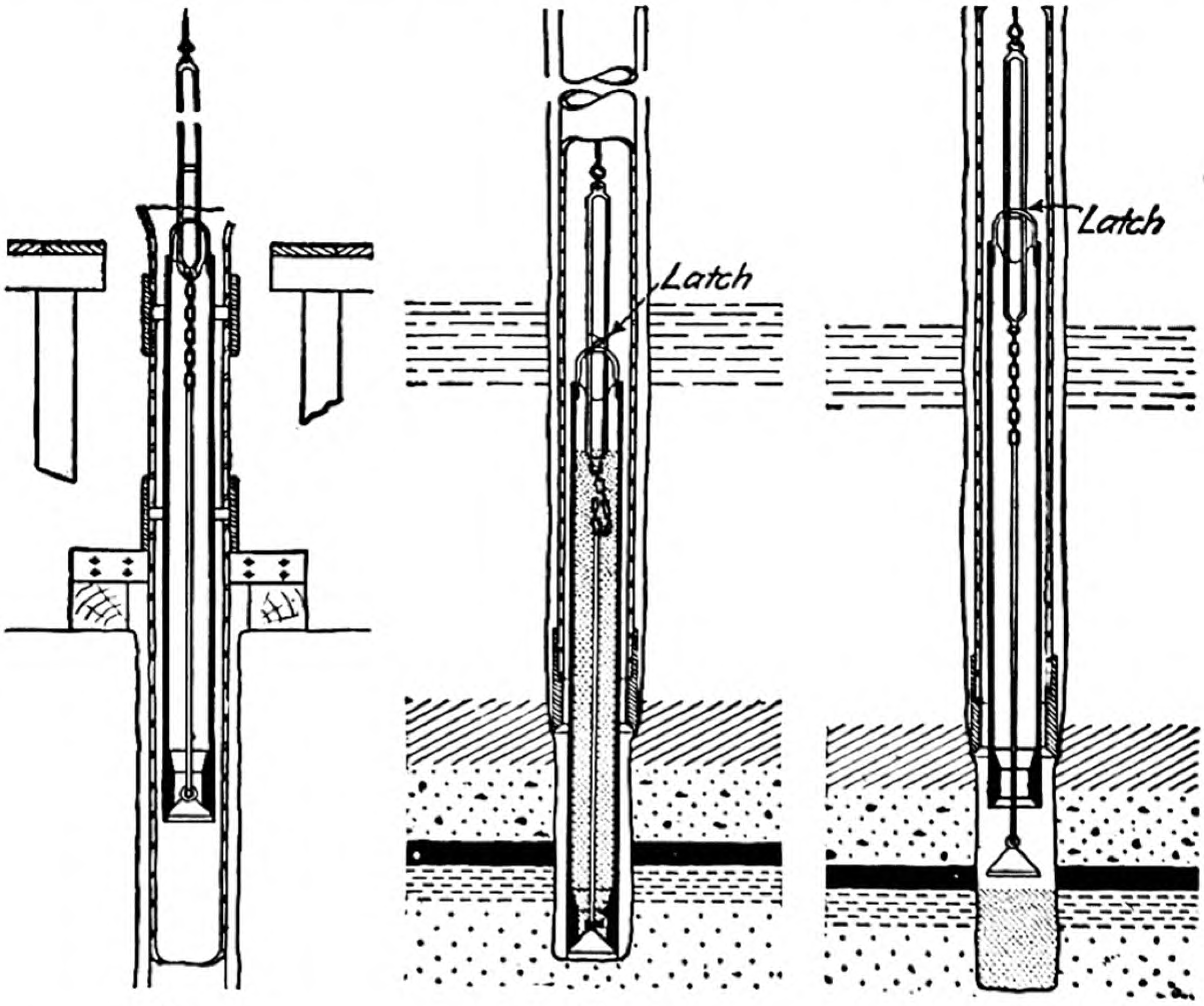
(Courtesy of MacClatchie Mfg. Co.)
FIG. 192.—Cementing head.

Cementing Heads.—To facilitate cementing operations, a type of casing head should be provided that is secure against high pressure and yet may be quickly disengaged from the casing to permit rapid insertion of control plugs in the descending fluid. Cementing heads are available in a variety of different types, some of which incorporate patented features. The head illustrated in Fig. 192 is widely used for this purpose. It embodies three drive-up slips and a cylindrical packing ring that can be expanded against the inside surface of the casing by turning an adjusting collar on a square thread. It is so constructed that upward pressure against the base assists in expanding the rubber packer and causes the slips to grip the casing more securely. This head is secure against very high pressures and yet can quickly be detached and reinserted. It can be disengaged from the casing without disturbing the connection to the cement pumps.

Figure 183 pictures a device designed to facilitate introduction of the upper cement plug into the descending stream of fluid in the casing, without disconnecting the head from the casing. This consists of a steel capsule connected in a vertical position above the casing head, and is equipped with a screw device which holds the upper cementing plug securely in the capsule until it is desired to release it. A manifold with suitable valve controls serves to equalize pressure above and below the plug

so that it may readily fall out of its capsule into the casing when released. After all of the cement has entered the casing, the plug is released from the capsule and the pump suction changed immediately, to drilling fluid or water, as may be desired, for pumping down the cement through the casing.

The Halliburton Depth-measuring Device.—It is desirable that the depth of the top cementing plug be known at all times. This may be estimated from a record of the volume of water or drilling fluid pumped down the casing after the plug, but a



(*After Swigart and Beecher, U. S. Bur. Mines Bull. 232.*)

FIG. 193.—Operation of latch-jack dump bailer. *A*, bailer entering well, lower end closed; *B*, bailer at bottom of well, ready to dump; *C*, after dumping, valve held open by latch.

more positive means is afforded by attaching a wire to the upper cementing plug, passing it through a stuffing box in the top of the Halliburton top-plug supporting capsule. The surplus wire is reeled on a small hand- or power-operated reel and passes over a measuring wheel the revolutions of which are mechanically registered (see Fig. 183). The device that records the number of revolutions of the measuring wheel can be calibrated to read directly in feet. This device also finds application in other operations where accurate measurement of depth to a reference point in a well is required.

Dump Bailers for Placing Cement in Wells.—For lowering cement into a well, special forms of bailers are employed, the latch-jack bailer illustrated in Fig. 193 being typical. Another type is closed at the lower end by an easily replaceable glass disk that is broken by a spring-loaded plunger on striking bottom. Dump shoes, designed to be attached to the lower end of a bailer in place of the ordinary bailer shoe and valve, or to the lower end of a joint or two of tubing or casing, are more positive

in action than latch-jack bailers and permit of lowering a batch of cement slurry to the bottom of a well with little likelihood of being dumped before that point is reached. A common form of dump shoe is provided with a cylindrical sleeve fitted to slide over the coupling which connects the device to the lower end of the bailer. Angle slots cut in the sleeve, operating on screw heads as guides, cause the bottom valve to open on striking bottom.

Casing Plugs.—For use in connection with the bailer method of cementing casing in wells, it is convenient to have a dependable means of closing the lower end of the column of casing before it is lowered into the fluid cement previously placed in the bottom of the well (see page 464). Casing plugs for this purpose may be had in several forms. The Baker Sure-Shot plug, construction of which is illustrated in Fig. 194, is a well-known type. This plug is made of cast iron and is equipped with a rubber facing ring and a canvas hood, the function of which is to wedge the plug in the lower end of the casing. After the cement has been placed in the bottom of the well, with the casing suspended so that it is free of the cement, the plug is lowered through the casing attached to the cable drilling tools or the dart of the bailer, with the canvas hood folded back so that it follows the plug during its descent. A valve in the lower part of the plug, normally closed, is forced open by the weight of the bailer or tools on the valve stem while the device is being lowered through the casing, thus permitting the well fluid to pass upward through the plug. After the plug has passed through the casing shoe, it is raised and the canvas hood, which is by this reversal of motion drawn down over the plug, securely wedges the latter in the casing shoe. After the casing has been set on bottom, a quick jerk breaks the few strands of wire by which the plug is suspended from the bailer or tools, so that the latter can be withdrawn. The plug, together with the small quantity of cement left inside the casing shoe, can readily be drilled out with either cable or rotary tools after the cement has set and hardened. Cementing plugs are necessarily made to pass through the casing with small clearance, and it is a good precaution, before attempting to use one, to lower a casing swage of appropriate size through the casing, to be certain that it has not become dented, bent or otherwise distorted during insertion.

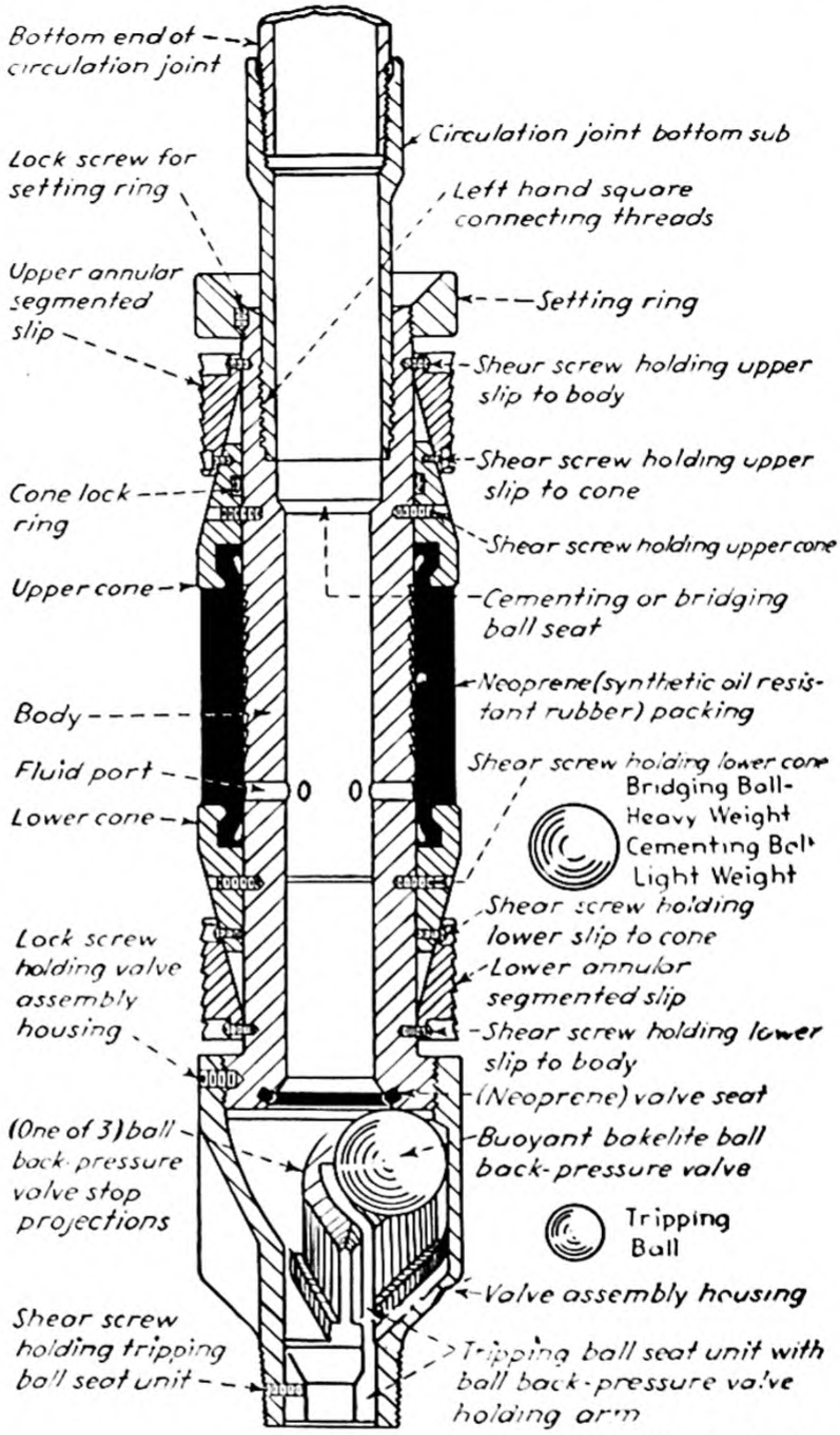
(Courtesy of Baker Oil Tools, Inc.)
FIG. 194.—Baker Sure-Shot cement plug.

Cement Retainers.—In several types of well-cementing operations involving pumping cement into wells through auxiliary columns of tubing, it is necessary to have a convenient means of closing the annular space between the tubing and the surrounding casing or of setting a bridging plug in the casing at a particular point. For this purpose, a cement retainer or a packer of special design may be used.

The Baker cement retainer consists essentially of a drillable packing assembly in the lower portion of which is incorporated a ball-type back-pressure valve. Mounted on the cylindrical body of the retainer between lead rings is a cylindrical packer of resilient material such as rubber, which may be expanded to close the space between the surrounding casing and the column of tubing on which the retainer is lowered from the surface. Two sets of annular, segmented, cast-iron slips, mounted one above and the other below the packer, provide a means of wedging the retainer firmly against

the inner walls of the casing so that it cannot be moved either up or down. Figure 195 presents an exterior view and a vertical section through one of several models of cement retainers now finding wide use in oil-well cementing operations.

Suspended on the lower end of a column of tubing or drill pipe to which it is connected by a "circulation joint," to the point where it is to be lodged in the casing,



(*Courtesy of Baker Oil Tools, Inc.*)

FIG. 195.—Baker model *K* cement retainer. Left: exterior view with circulation joint attached. Right: sectional drawing showing interior construction.

the retainer is tripped by dropping a steel ball down the tubing from the surface through the water or drilling fluid which fills the tubing and annular space. The tripping ball eventually comes to rest on a conical seat in the lower part of the retainer and closes the outlet from the tubing against descending fluid. The circulating pumps connecting with the tubing at the surface are then operated slowly to build up fluid pressure gradually within the retainer. As the pressure increases, fluid is

forced through fluid ports behind the resilient packer, expanding the latter until it fills the annular space and presses against the inner wall of the casing. The packer, being confined by the casing against further lateral expansion, is elongated by continuing pressure from within, eventually shearing screws holding the upper slips to their supporting cone and pressing the slips upward against the upper setting ring. Further upward movement of the cone shears the screws holding the upper slips together, and the released slips are then forced outward until their wickers grip the casing. The pump pressure is further increased, and eventually a screw supporting the tripping ball and its seat is sheared, allowing the ball and seat to be forced out of the retainer body so that it falls into the well below. This also releases the bakelite back-pressure float valve so that it is free to rise against its inverted seat. Upward strain is then taken at the surface on the string of tubing that supports the retainer. This causes the upper slips to grip the casing securely, which in turn prevents any upward movement of the packer. As the upward strain increases, the body of the retainer moves upward within the packing assembly, shearing screws that hold the lower cone and slips together and causing the lower slips to grip the casing, thus preventing further downward movement of the retainer. Continuation of the upward strain on the supporting tubing further compresses the packer longitudinally, and expands it laterally so that it bears firmly against the casing. This completes the packing-off cycle.

The circulation joint that connects the retainer with the tubing consists of a cylinder telescoping about a tubular mandrel. In the lower end of the cylinder, about the mandrel, is a valve assembly. When the mandrel is telescoped upward within the cylinder, fluid pumped down through the tubing passes out through the circulation joint into the annular space between the tubing and casing; but when the circulation joint is fully extended by taking light strain on the supporting tubing at the surface, the circulation joint valve is closed and fluid passing down through the tubing finds its only outlet through the retainer below.

With the cement retainer thus wedged in the casing, cement slurry mixed and ready to be pumped down the tubing, a light strain is taken on the tubing to assure that the circulation joint is closed, and circulation is started. Water or drilling fluid is first circulated to be certain that the passage way for the cement is free of obstructions; when this is assured, cement slurry is pumped down the tubing and through the retainer. Once passed down through the retainer, the upward-seating bakelite back-pressure valve prevents cement from flowing back into the tubing, even though pump pressure is discontinued. To remove any possibility of subsequent hydrostatic pressure unseating the back-pressure valve, a second ball—called a "cementing ball"—is dropped into the tubing just before the last of the cement slurry. This ball eventually closes the upper inlet to the retainer. When it reaches its seat, pump pressure builds up quickly, the tubing is lowered, telescoping the circulation joint and opening its valve, thus allowing the small residue of cement in the tubing to pass out into the annular space between the tubing and the casing. The tubing is then turned 15 or more revolutions to the right, thus disengaging the left-hand threads connecting the mandrel of the circulation joint to the retainer. The tubing and circulation joint may then be removed from the well, leaving the retainer still wedged in the casing. After the cement has set, the retainer, being constructed entirely of drillable materials, is readily drilled out of the casing along with such cement as fills its passages and the casing below.

Surface Equipment for Mixing and Pumping Cement Slurry into Wells.—The equipment provided for mixing cement used in excluding water from wells must be capable of accomplishing its purpose rapidly and thoroughly and with accurate proportions of water and cement. Many tons of cement will often be used in a single

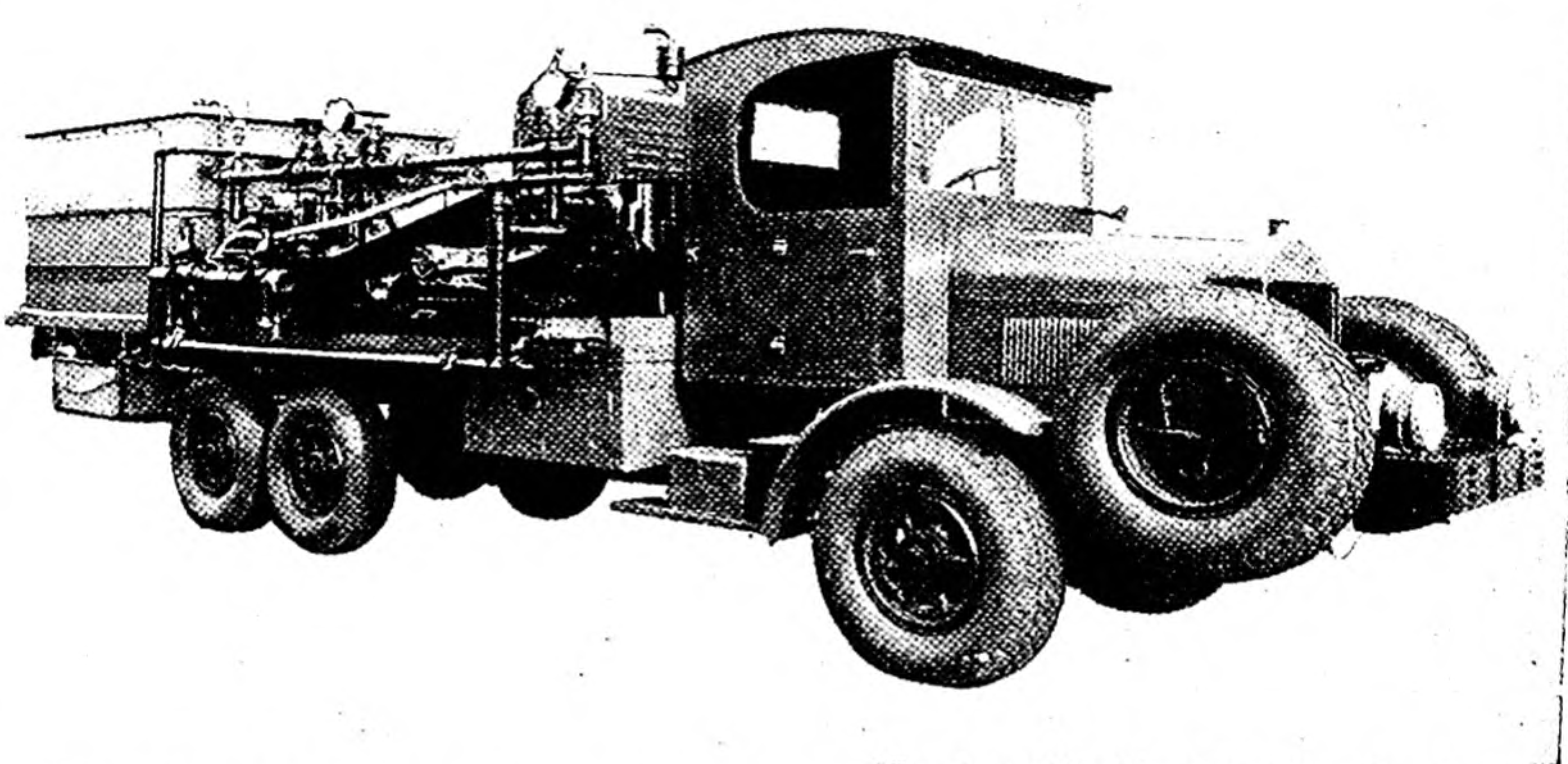
operation and the cement slurry must be mixed and forced to its position in the well as quickly as possible: hence large pumping and mixing equipment must be provided. As much as 2,000 sacks of cement, or 94 tons, have been used in some cementing operations and the entire procedure in mixing and placing the slurry must usually be completed in less than an hour, inasmuch as the slurry will not set satisfactorily if kept in motion beyond this time.

Several different types of equipment are used for mixing the cement. A primitive method involves mixing by hand, a group of from four to six men distributed about two flat metal or wooden boxes (10 ft. long, 6 ft. wide and 2 ft. deep), stirring with hoes while water is added to the dry cement previously dumped into the box. Batches of cement are mixed in each box alternately. Two steam-driven reciprocating pumps mounted on the bed of a motor truck are used in forcing the cement down the casing or tubing in the well. One of these is a low-pressure pump capable of operating against a pressure of 250 lb. per sq. in., and the other a high-pressure pump designed to deliver fluid under pressures as high as 1,000 lb. per sq. in. The suction lines of the pumps are manifolded so that either may draw cement slurry from a small metal tank placed below the mixing boxes in such a way as to receive the flow of slurry from either tank when wooden plugs controlling the discharge outlets are withdrawn. To gauge the water used in mixing the cement, a water meter or a gauging tank is used. The water may be passed through one of the pumps to give it sufficient pressure to permit it to be forcefully sprayed through a hose and nozzle into the dry cement in the mixing boxes. Operating systematically on a pile of dry cement, a man is by this means able to mix the cement rapidly and thoroughly.

The cement slurry is passed ordinarily through the low-pressure pump but, if for any reason pressures in excess of 250 lb. per sq. in. are necessary, the high-pressure pump will be brought into service. Fittings and valves in the system of piping connecting with the cementing head on the casing or tubing in the well must be capable of withstanding pressures in excess of the maximum delivery pressure possible with the high-pressure pump. Connections with the well head must be flexible so that the casing or tubing may be raised or lowered when necessary. Arrangements at the casing head that permit of rapid introduction of the cementing plugs into the casing are important.

Cementing operations are generally entrusted by the operator to a service organization that sends its trained personnel and specialized equipment to the well, takes charge of and assumes responsibility for proper conduct of the work. Oil-well cementing service organizations, which offer specialized well-cementing service in many American oil fields, are usually equipped with motor trucks each of which carries all of the essential equipment except that normally found at the well. From this portable equipment, all necessary connections can quickly be made with the well to be cemented (see Fig. 196). Two horizontal reciprocating pumps are provided, which may be either steam driven or powered with an auxiliary internal-combustion engine. One of the two pumps is 14 by 6¾ by 12 in. in size and the other 10 by 4½ by 10 in. They are designed to deliver cement slurry to the well under pressures as high as 3,000 lb. per sq. in. The cementing equipment on the service truck also includes a two-compartment tank, used in measuring the fluid pumped into the well, and a cone-jet type of cement mixer and necessary piping or armored hose for connecting the several parts of the equipment with each other and with the near-by well. The measuring tank is employed in measuring the water used in mixing the cement slurry and also in measuring the displacement fluid pumped down through the casing after the cement. Each of the two compartments of the measuring tank holds exactly 100 cu. ft. of fluid. Connections are provided at the well, through high-pressure steel pipe or armored hose, with a special cementing head mounted on top

of the column of casing to be cemented. Water and steam connections must also be provided with the pumps and mixing equipment. The cement to be used, delivered in sacks, is placed near by. The pumps are connected with the double-compartment measuring tank, so that one pumps cement slurry, mud fluid or water into one compartment of the measuring tank while the other transfers fluid from the other compartment to the well. A conveniently arranged system of valves permits of rapidly changing the pump connections from one to the other of the two measuring compartments. One compartment of the measuring tank is thus being filled while the other is drained. The pumps may also be manifolded together in tandem, the suction line from the larger of the two pumps drawing fluid from the delivery line of the smaller pump. This arrangement of the pumps may be used in cementing deep wells after all of the cement has entered the casing, when high pressure may be necessary



(Courtesy of Perkins Cementing Co., Inc.)

FIG. 196.—Well-cementing equipment permanently mounted on motor truck.

to force it into position against the well friction. Another service organization uses 5- by 8-in. triplex pumps capable of delivering 250 gal. per min. at 540 lb. pressure and operating at delivery pressures as high as 4,500 lb. per sq. in.

The Cone-jet Mixer.—For rapidly mixing water and dry cement in any desired proportions, the cone-jet mixer patented by E. P. Halliburton is widely used (see Fig. 197). This is usually set up on the ground at one side of the service truck. It is provided with a broad-mouthed hopper into which the dry cement is dumped. The hopper tapers toward the bottom where it connects with a horizontal pipe through which a jet of water is forced under either hydrostatic or pump pressure sufficient to deliver the mixed cement slurry to the measuring tank. A record of the number of sacks of cement used and of the volume of cement slurry produced, as indicated by gauging in the measuring tank, affords an accurate check on the volume of water used and permits of close control of the percentage of water in the mix. As much as 1,000 sacks of cement can be mixed in 1 hr. with a single mixer of the cone-jet type.

Bulk Delivery of Cement.—In some regions, the Halliburton well-cementing service includes bulk delivery of the cement to the well. Instead of shipping dry cement from the manufacturing plant to the well in sacks or bags, the well-cementing company maintains a supply of different brands and types of cement, stored in large steel bins in a centrally located distributing plant. From this storage plant, where

mechanical loading and unloading and weighing facilities are provided, the cement is transported to the individual wells where cementing is to be done, in enclosed tank motor trucks with built-in screw conveyer equipment to facilitate delivery of the cement directly into the mixing facilities at the well. By this method of transporting and handling the cement, there is less likelihood of loss and deterioration due to breakage of sacks, exposure to moisture and aging in warehouses. Also, cement in any desired quantity is more promptly available to the operator than if he had to await delivery from a distant cement plant.

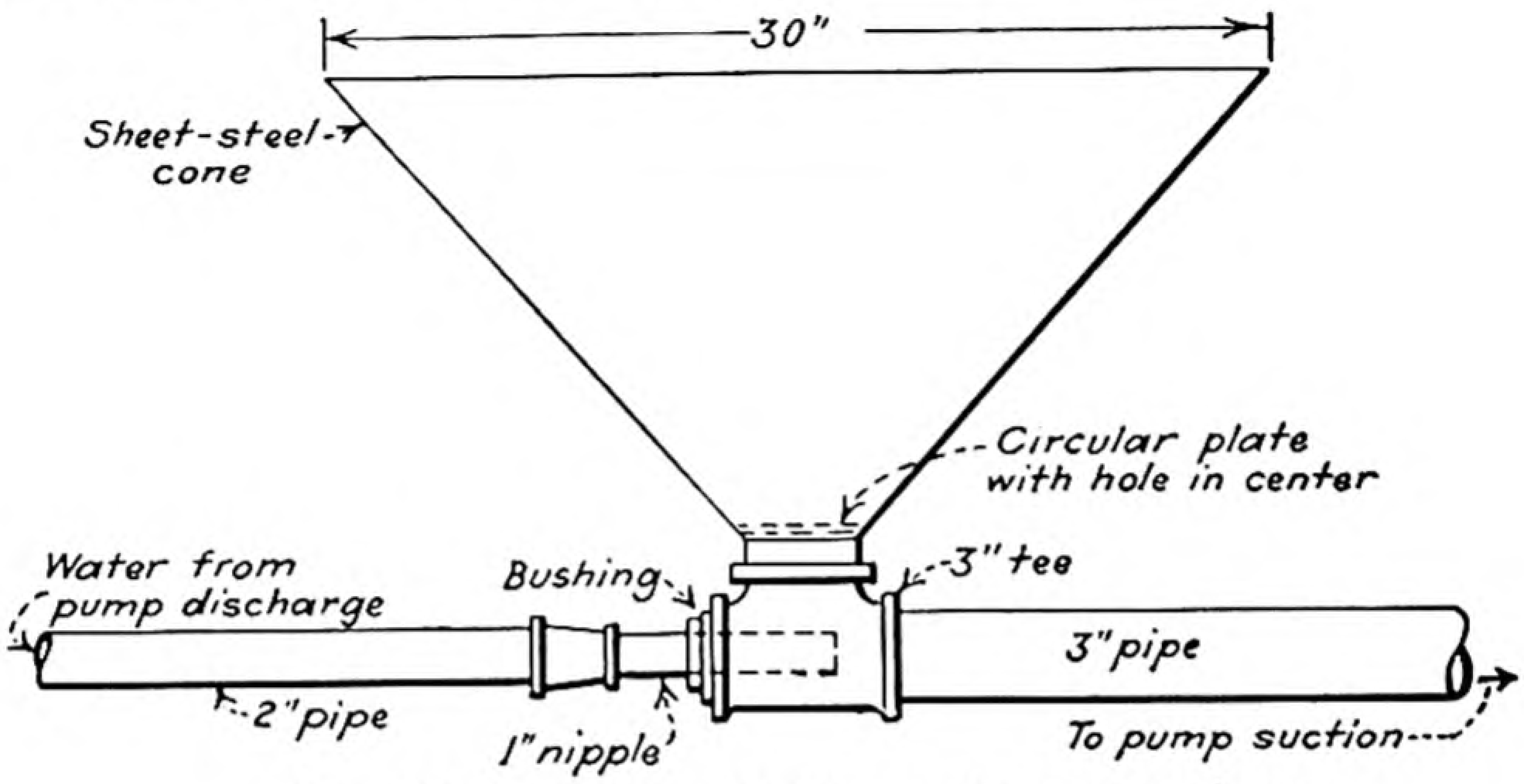


FIG. 197.—Cone and jet type of cement mixer.

PROPERTIES OF CEMENTS USED IN EXCLUDING WATER FROM WELLS

As is well known, portland cement is manufactured by a process involving the sintering of a mixture of clay and limestone in certain proportions. The cement clinker possesses no hydraulic properties until it is finely ground. During the grinding process, calcium sulphate (gypsum) is added to control the setting time and rate of hardening. The cement thus produced is composed of a mixture of calcium oxide (CaO), aluminum oxide (Al_2O_3), silicon dioxide (SiO_2), magnesium oxide (MgO), ferric oxide (Fe_2O_3) and sulphur trioxide (SO_3). These oxides are combined in the form of tricalcium silicate ($3CaO.SiO_2$), dicalcium silicate ($2CaO.SiO_2$), tricalcium aluminate ($3CaO.Al_2O_3$) and tetracalcium aluminoferrite ($4CaO.Al_2O_3.Fe_2O_3$). Pentacalcium trialuminate ($5CaO.3Al_2O_3$) and dicalcium ferrite ($2CaO.Fe_2O_3$) may also be present, but are not essential constituents. To these constituents we might add potassium oxide (K_2O), sodium oxide (Na_2O), manganese oxide (Mn_2O_3) and perhaps other oxides that are frequently present as impurities to the extent of 2 per cent or less.

Hydration and Setting of Cement.—The chemical changes which occur after the ground cement has been mixed with water and which produce the phenomenon known as "setting," are complex and somewhat uncertain. Most authorities agree, however, that the setting of cement occurs in stages involving, first, the hydration of tricalcium aluminate and perhaps some alumina. These products are amorphous at first, but

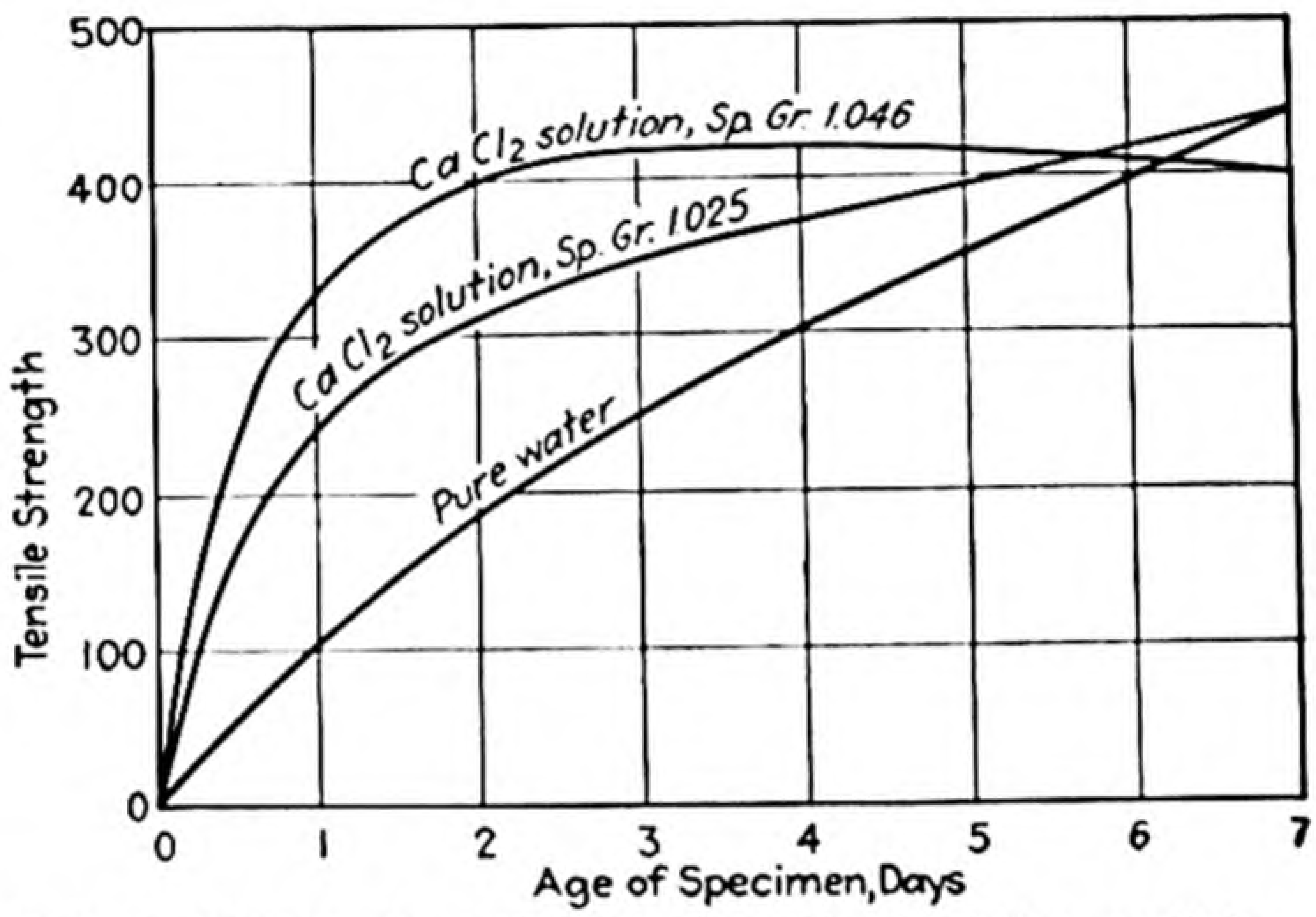
later crystals of tricalcium aluminate are formed along with crystals of calcium sulfoaluminate, the sulphur in the latter compound being contributed by the gypsum. Any free lime present is also hydrated. Within 24 hr., the tricalcium silicate begins to hydrate, crystallizing the lime content, while the less basic calcium silicate and silica hydrate form a colloidal gel. Hydration of the calcium silicates is not ordinarily complete within 28 days. It is thought that the initial set is influenced by small amounts of electrolytes which retard coagulation of the colloids. It thus appears that the early crystallization and consolidation of the cement slurry are due to hydration of the tricalcium aluminate and partial hydration of the tricalcium silicate. Later increase in strength is due to continued hydration of the tricalcium silicate and dicalcium silicate. Neither the tricalcium aluminate nor the tetracalcium aluminoferrite contributes much to the ultimate strength of the cement. However, the latter gives protection against the destructive influence of sodium or magnesium sulphate ground waters which react with hydrated tricalcium aluminate to form compounds causing expansion and disintegration of the hardened cement. The fluidity of the mixture before solidification occurs is chiefly affected by the dicalcium silicate and tricalcium aluminate, and to a lesser extent by tetracalcium aluminoferrite.

From the physical point of view, three periods are recognized in the hydration of portland cement: the so-called "initial set," the "final set" and the hardening period. The changes that characterize these periods are the result of chemical readjustments which, as explained above, require time to achieve. The initial set is said to have occurred when the cement slurry has lost its plasticity and becomes friable to such a degree that two pieces of a broken specimen will not unite to form a homogeneous mass when placed in close contact. The plasticity is not restored by remixing with water. The slurry should be undisturbed for a time before the initial set occurs. Agitation throughout the period preceding the initial set will prevent the cement from hardening properly and, even though it may consolidate into a coherent mass, its strength will be greatly impaired.

After the initial set has occurred, the cement undergoes further chemical change as a result of which it acquires greater hardness until the final set has been achieved. It is arbitrarily defined as that condition when a certain degree of rigidity is attained, as determined by a penetration needle of standard proportions. With most portland cements, the final set occurs in from 2 to 5 hr. after the initial set. It is of no particular significance in oil-well cementing. Following the final set, a 10- to 28-day period of further chemical readjustment results in gradual increase in strength and hardness. This period, during which the material gradually hardens and gains strength, is important in oil-well

cementing operations in that during this time, or a part of it, the well must be left undisturbed in order that the cement may not be subjected to stresses beyond its ability to resist.

Accelerators.—The time of final set is somewhat diminished and the period of hardening is reduced to as little as 3 or 4 days by adding a chemical accelerator, either to the cement or to the water used in preparing the slurry. A variety of accelerators are available on the market under different trade names, but calcium chloride is the active reagent in nearly all of them. An alkaline substance is sometimes added to reduce the corrosive tendency of the calcium chloride. The graphs of Fig. 198 demonstrate the advantage of calcium chloride in achieving early strength. Other reagents that may be used to accelerate the setting



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 198.—Effect of age and influence of accelerators on tensile strength of cement.

time include calcium oxychloride, sodium and potassium hydroxide and sodium silicate. Most of the sulphates except calcium sulphate (gypsum) accelerate the setting and hardening action slightly.[27]

In the so-called "high-early-strength" cements, the chemical accelerator is intimately mixed with the cement by the manufacturer. This method of using the accelerator is preferable to methods that involve adding it to the cement in the field. However, if the latter plan is necessary, uniform distribution of the reagent can be achieved by dissolving a suitable amount in the water used in mixing the slurry. Calcium chloride may be used in this way to the extent of 2 or 3 per cent of the dry weight of the cement. Or 3.5 lb. of calcium chloride may be dissolved in each cubic foot of water used, producing a solution having a density of 1.02 to 1.03. Such addition permits of using the ordinary construction grade of portland cement for cementing surface and intermediate casings and for all subsurface operations where bottom-hole temperatures are not high and where resistance to sulphate ground waters is not a factor.

Addition of calcium chloride causes rapid hydration of the cement and develops earlier maximum temperature (see Fig. 198) and more rapid set with high early strength, and often, greater ultimate strength. The thickening time is also diminished by addition of calcium chloride, but when only 2 or 3 per cent is used, the limit of pumpability is seldom reached in less than 1 hr. Addition of more than 3 per cent of calcium chloride generally reduces the ultimate compressive strength and further shortens the thickening time, and should therefore be avoided.

Retarders.—For use in deep wells where unusually high temperatures are encountered, the cement may set so rapidly that it becomes necessary to resort to the addition of retarding agents which prolong the setting time. Gypsum, sugar, lime, various gums and organic compounds such as sodium tannate may be used for this purpose. The time of thickening, setting and hardening may also be prolonged in the process of manufacture by coarser grinding of the cement clinker, or by altering the chemical composition. Use of ice water in mixing cement will also tend to reduce slurry temperature in deep wells and thus prolong the setting time.

Variables Influencing the Behavior of Portland Cement in Oil-well Service

The setting time of portland cement in oil-well service is influenced by many variables, the more important of which include the chemical composition, the percentage of water used in mixing the slurry, the temperature, pressure, the age of the cement and conditions attending storage and the degree of fineness to which the cement particles are ground. The setting properties may also be influenced by contact with ground waters containing certain dissolved salts or by the presence of flowing oil or gas.

Influence of Chemical Constitution of Cement on Setting Time.—From the chemical point of view, the setting time of portland cement is influenced by the proportions of alumina and ferric oxide that it contains. The greater the percentage of these constituents, the more rapidly will the material set. High silica content is characteristic of slow-setting cements. The tricalcium aluminate and tetracalcium aluminoferrite hydrate set rapidly, and quick-setting cements contain a larger than normal percentage of these constituents. Tricalcium silicate and dicalcium silicate set less rapidly and large percentages of these constituents are characteristic of slow-setting cements. The amount of gypsum that has been added, as indicated by the percentage of sulphur trioxide in the chemical analysis of the cement, also has a determining influence on the setting time. Less than 2 per cent of this constituent will retard the setting time, but larger amounts will cause the cement to set more rapidly.

Influence of Saline Ground Waters on Setting Time of Cement.—The influence of saline ground waters on the setting qualities of portland cement in oil-well service has been noted by many observers. The cement is quite sensitive to comparatively small

percentages of some of the dissolved salts commonly present in oil-field brines and, if there is flow of saline water into the well during placement of the cement or before the initial set has occurred, its properties may be greatly altered. In extreme cases, the cement does not set and has to be pumped out of the well. Dilute solutions of chloride salts reduce the setting time, calcium and magnesium chlorides being much more active in this connection than sodium chloride. Contact with sulphate solutions in certain concentrations will delay the setting time, though small percentages may hasten it. Sodium carbonate, or any reagent liberating free OH ions, acts as an accelerator. The graphs of Fig. 199 give results of tests made with a typical oil-well cement gauged with 50 per cent of water containing varying percentages of dissolved

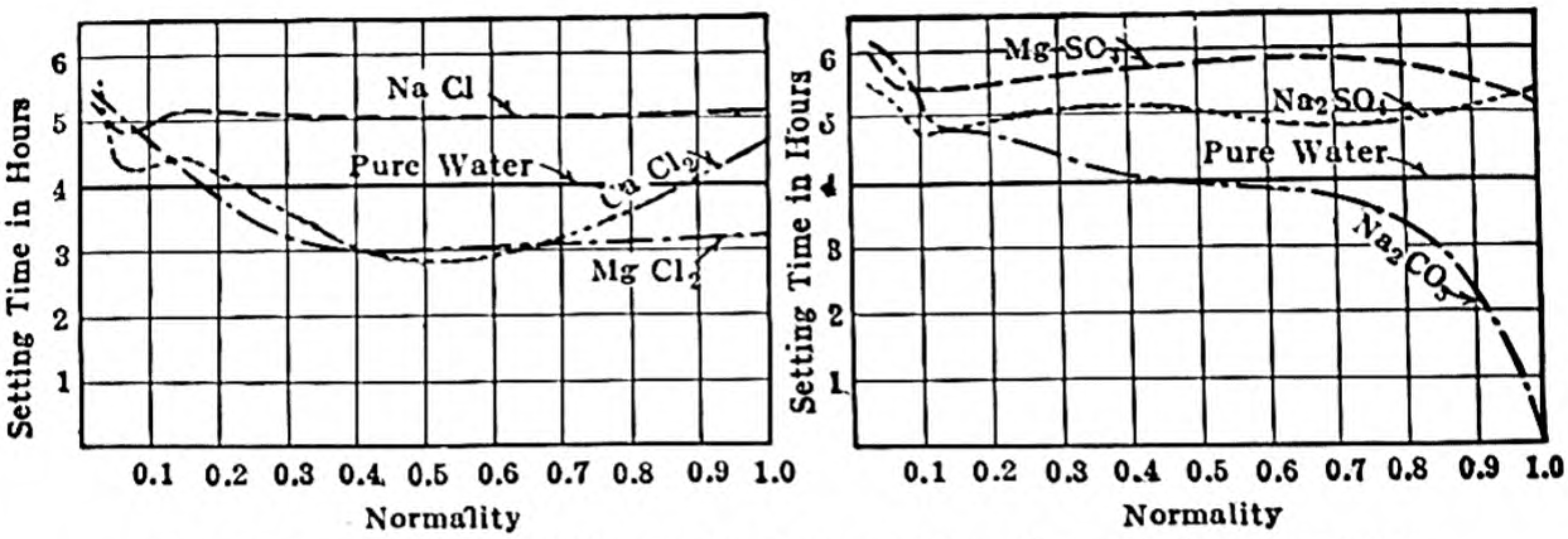


FIG. 199.—Influence of dissolved salts on setting time of oil-well cement.

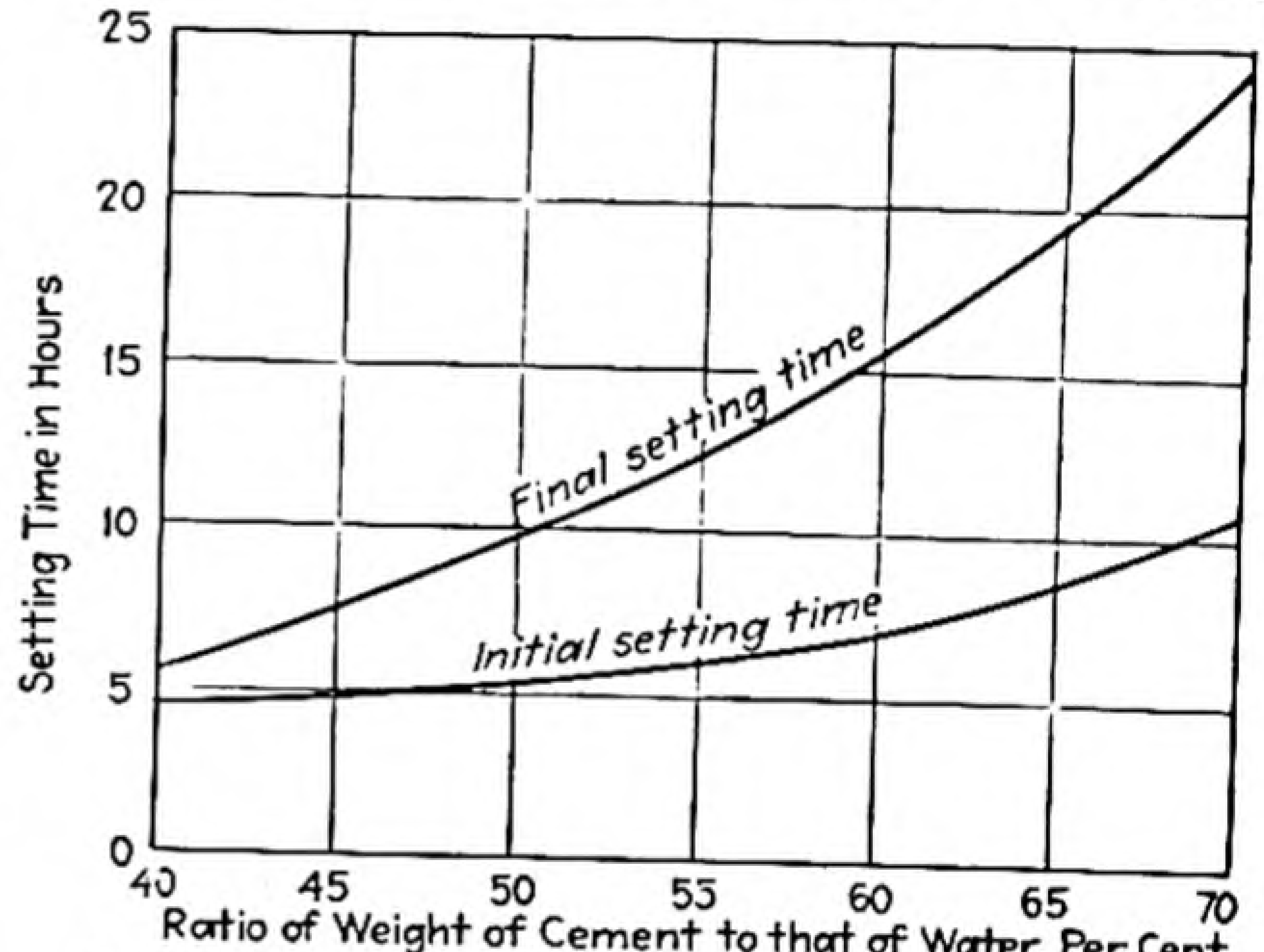
salts commonly present in oil-field ground waters. If brackish surface waters are used in mixing cement, they may seriously alter the setting time.

Influence of Sulphate Ground Waters in Causing Unsoundness of Cement.—Some of the salts present in oil-field ground waters, particularly salts of the alkalies and alkaline earths, in addition to influencing the setting time of portland cement will, on prolonged contact, cause it to disintegrate. Sulphates of magnesium and sodium are particularly active in causing unsoundness in neat portland cement. When cement that has set and hardened is exposed to contact with solutions of these salts, they have a tendency to react on the hydrated calcium aluminate content, forming new compounds that result in recrystallization, expansion and crumbling of the cement. Cement containing less than about 3 per cent of tricalcium aluminate seems to be immune to this effect but, when this constituent is present in greater amount, sulphate waters may have a detrimental effect. It appears that sulphate ground waters are less destructive at high temperatures (200°F.) than at lower temperatures (100°F.). Hence, there is less necessity for prescribing sulphate-resistant cements for use at great depths where temperatures are high, than in shallow, cooler formations. Cements containing high percentages of ferric oxide (tetracalcium aluminoferrite) are more resistant to sulphate waters than ordinary cements. Sulphate solutions and calcium chloride solutions also have a corrosive influence on steel casing; hence, it is especially important that it be protected, through horizons containing water solutions of these salts, by a sheath of cement resistant to their influence.

Unsoundness of cement may also be due to expansion after setting, as a result of belated crystallization of free lime and magnesia present in the cement itself. More than 5 per cent of magnesia is considered detrimental in a portland cement for this reason. Prospective failure of the cement by this action will not be apparent at first, but may eventually result in crumbling and disintegration and its ultimate failure in water exclusion. The amount of "laitance" which forms on top of a cement slurry

during the setting period is considered to be indicative of the degree of unsoundness of the cement.

Influence of Water Dilution on Setting Time of Cement.—Dilution of the cement-water mixture with additional water prolongs the setting time (see Fig. 200). If the cement slurry is diluted to such a degree that the cement particles are held apart by suspension in water, they cannot be expected to form a coherent mass, even though setting of the individual particles does occur. Though a smaller percentage of water would be preferable, a slurry containing 35 or 40 per cent as much water as cement (by weight) is about as thick as can be rapidly handled through pumps, piping and other equipment used in oil-well cementing. Although excessive dilution of cement slurry may prevent the formation of a coherent, solid mass, as a result of the individual grains taking their initial set when not in close contact, yet, if there is adequate time for the cement particles to settle before the initial set occurs, a successful job is possible, even with slurries containing 70 per cent or more of water. Because of settling tendencies, the lower part of a cement plug may be stronger and more dense than that at the top.



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 200.—Effect of dilution of cement slurry on setting time. (Slurry mixed with solution of calcium chloride, sp. gr. 1.005.)

Though cement may be pumped into the well with only 35 or 50 per cent of water, it will frequently be further diluted by admixture with the well fluid and with the water used in pumping the cement down through the casing or tubing. It is well known that in pumping fluids through a pipe the fluid near the center moves more rapidly than that near the walls of the tube as a result of frictional resistance. Furthermore, turbulence is usually induced. Hence, when cement is pumped into a pipe containing water or mud, there is more or less dilution of the first portion of the cement introduced. A similar effect results when water is pumped in after the cement. The amount of dilution and admixture would vary with the diameter of the pipe and the velocity of flow, being greater in pipes of large diameter and at high-flow velocities. Even when barriers are used between the cement and the well fluid, as in the Perkins method, the two fluids must come into contact when the cement emerges below the casing shoe. Reversal in the direction of flow as the cement strikes the bottom of the well and is deflected upward, and contamination with mud from the walls as it rises, inevitably result in considerable dilution of the material that forms the top of the plug. Again, in the method of cementing direct through the casing without barriers, unless pumping is discontinued at the proper time, water forced in below the cement will rise slowly and become diffused through the latter by reason of its lower density.

Influence of Mud Contamination on Setting Properties and Strength of Cement.—Dilution with mud may seriously reduce the strength of cement, though it may set satisfactorily even when contaminated with considerable amounts. The mixture will be coherent and impermeable, but it lacks strength. Briquettes made of a mixture of equal parts of a mud-laden fluid of specific gravity 1.2 with a 50 per cent cement grout had a compressive strength of only 97 lb. per sq. in. after setting 10 days in air, while a pure 50 per cent cement grout, under similar conditions, had a compressive strength of 2,210 lb. per sq. in.[39]

Probably only the upper portion of a cement plug is contaminated with mud to an important degree, the heavier cement, injected below the column of mud, tending to float the latter so that the lower part of the plug should be fairly free of mud. However, where conditions are such as to permit the cement to channel through a column of heavy mud, it is easy to understand how contamination of the entire body of cement might result. Engineers in the employ of the Humble Oil and Refining Company conducted a series of tests on cores taken in drilling cement plugs out of casings. The cement was found to lack strength in many cases and to have a chalky, unsound appearance. Petrographic and chemical inspection indicated that mud contamination was the principal cause and the conclusion was reached that even small amounts of drilling mud are capable of doing considerable damage.[26]

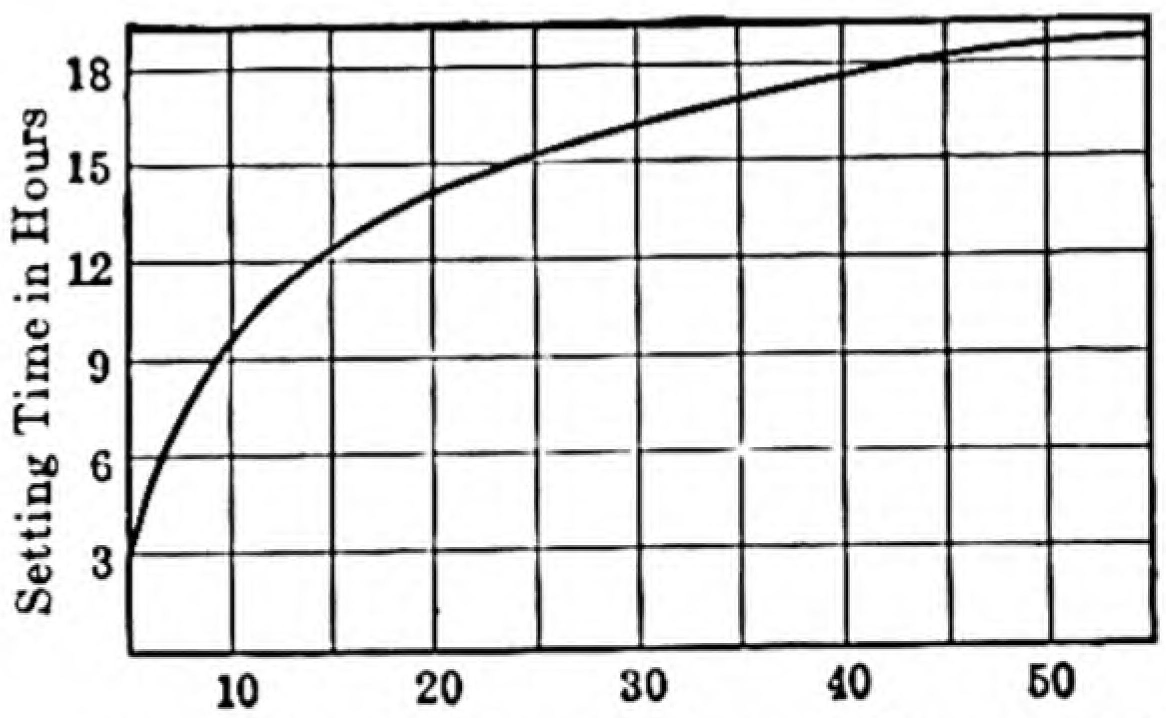


FIG. 201.—Influence of oil dilution on setting time of oil-well cement.

Influence of Oil Contamination and Flowing Gas on Setting Properties of Cement.—Mixture of oil with portland cement slurry will not prevent setting, providing there is sufficient water present to hydrolyze the material properly, but it has the effect of prolonging the setting time. Figure 201 illustrates the effect of oil admixture in delaying the initial set of a typical oil-well cement. Oil may also prevent the cement from adhering to the casing and leave a crevice through which water eventually finds its way to the lower part of the well. Perhaps this leakage is negligible at first, but it is later increased by the solvent action of percolating alkaline ground waters.

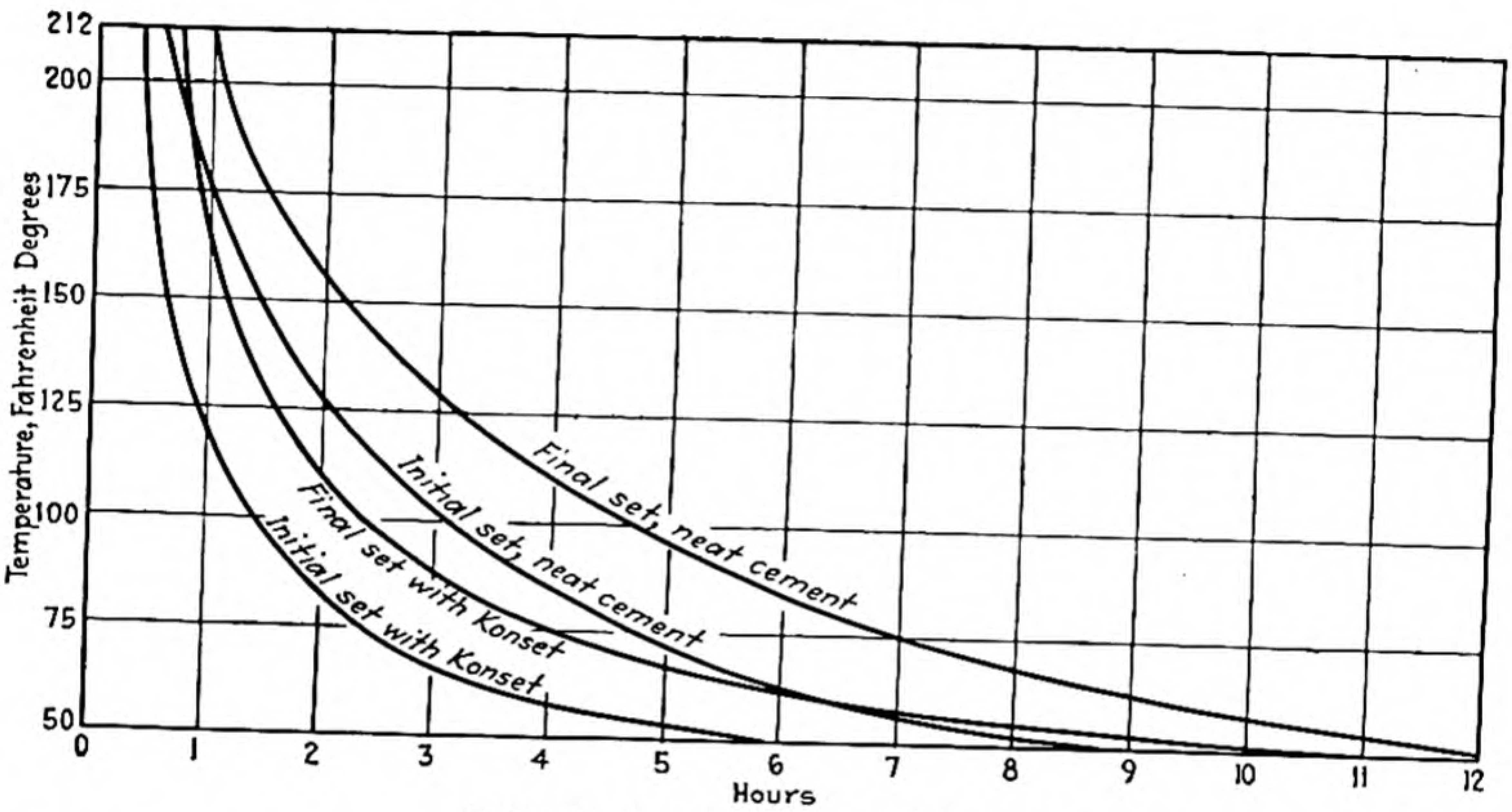
The presence of gas in the bottom of a well is a more serious matter. Violent agitation of the cement sometimes prevents it from setting into a coherent mass, while even comparatively small quantities of gas continually supplied from a point below the plug will, in seeking an outlet, leave pores in the cement which will later become channels for the passage of water. If a well is producing gas in quantity, it should be possible to hold pressure on it during the process of cementing to prevent flow of gas. Preliminary mudding under pressure will often "kill" the gas so that cementing operations may be safely conducted at lower pressures.

Influence of Fineness of Grinding of Cement on Setting Time.—The setting qualities of portland cement are also influenced by the degree of fineness to which the material is ground. Most cements are ground so that all but 2 or 3 per cent of the material will pass through a 100-mesh screen, while about 85 per cent usually passes 200 mesh. The particles coarser than 100 mesh are probably inert and have no hydraulic properties. Tests reported by Meade* with a certain cement show a setting time of 30 min. when 95 per cent passes 200 mesh, while the same material ground so that only 75 per cent passes 100 mesh requires 170 min. in which to take its initial set. Uniformity in sizing is regarded as one of the most important considerations in the manufacture of a reliable product.

A screen analysis of cement does not provide so satisfactory an index of setting qualities as a measure of the specific surface presented by its component grains. The size distribution of grains is also of interest in this connection. An apparatus

* MEADE, R. K., "Portland Cement, Its Composition, Raw Materials, Manufacture, Testing and Analysis," 3d ed., Chemical Publishing Company, Easton, Pa., 1926.

and method for determining these factors have been developed. The apparatus employed is a type of turbidimeter in which a photoelectric cell and microammeter are used to measure the amount of light passed per unit of time from a light source of constant intensity through a suspension in kerosene of a standard amount of the cement. A known relation between the magnitude of current flowing through the microammeter and the specific surface of the suspended material enables one to estimate quickly the surface area of the cement particles, which is customarily expressed in square centimeters per gram. Specific surfaces of various portland cements are found to range from 1,100 to upward of 2,800 sq. cm. per gram. Particle-size distribution is estimated by observing changes in turbidity as the cement particles settle from suspension. The settling time intervals are converted to particle sizes by application of Stokes' law.[29]



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 202.—Effect of temperature and accelerators on the setting time of 40 per cent cement slurry.

Influence of Temperature on Setting Time of Cement.—The setting time of portland cement is greatly influenced by temperature. As indicated by the graphs of Fig. 202 some cements set in one-third of the time at 150°F. that is required for the same cements at 60°F. In the deeper wells, bottom-hole temperatures of 150°F. or more are not unusual and the setting time is decreased to such an extent that a difficult problem is sometimes presented in mixing and placing a large quantity of cement in position outside of the casing before the initial set occurs. To compensate for the accelerating influence of high temperature, cements used in deep wells may contain a chemical retarding agent or be coarsely ground; or they may be slurrified with ice water as a means of reducing bottom-hole temperatures.[30,32]

Heat of Hydration of Cement.—Chemical reaction of water upon the constituents of portland cement in the process of setting develops considerable heat. Calorimeter tests indicate that the amount of heat liberated by hydration of cement ranges from 60 to 115 cal. per gram, depending upon its composition and fineness of grinding. Liberation of heat apparently reaches a maximum in from 4 to 8 hr. after the cement is placed, or shortly after the initial set occurs, and may produce temperatures in the cement as much as 50°F. above that of the surrounding formations. However, liberation of heat continues to a lesser extent during the subsequent period of harden-

ing and is conducted away very slowly. Temperature surveys in wells, inside of cemented casings, disclose higher than normal temperatures in cemented intervals for a period of several days after the cement has been placed (see Fig. 279). Tricalcium aluminate is the constituent responsible for most of the heat, though hydration of tricalcium silicate is also an exothermic reaction.

Influence of Pressure on Setting Time and Strength of Cement.—Pressure has an important influence in accelerating the setting time of cement slurry in deep wells, where pressures of the order of several thousand pounds per square inch are not unusual. The time limit of mobility or pumpability with a typical portland cement was reduced by 1 hr. 40 min., or 54 per cent, by increasing the pressure imposed on the slurry from atmospheric pressure to 5,000 lb. per sq. in. The time of initial set was reduced from 3 hr. 40 min. to 2 hr. 10 min. High pressure is also responsible for an increase in the compressive strength of cement of as much as 30 per cent in some cases.[30,32]

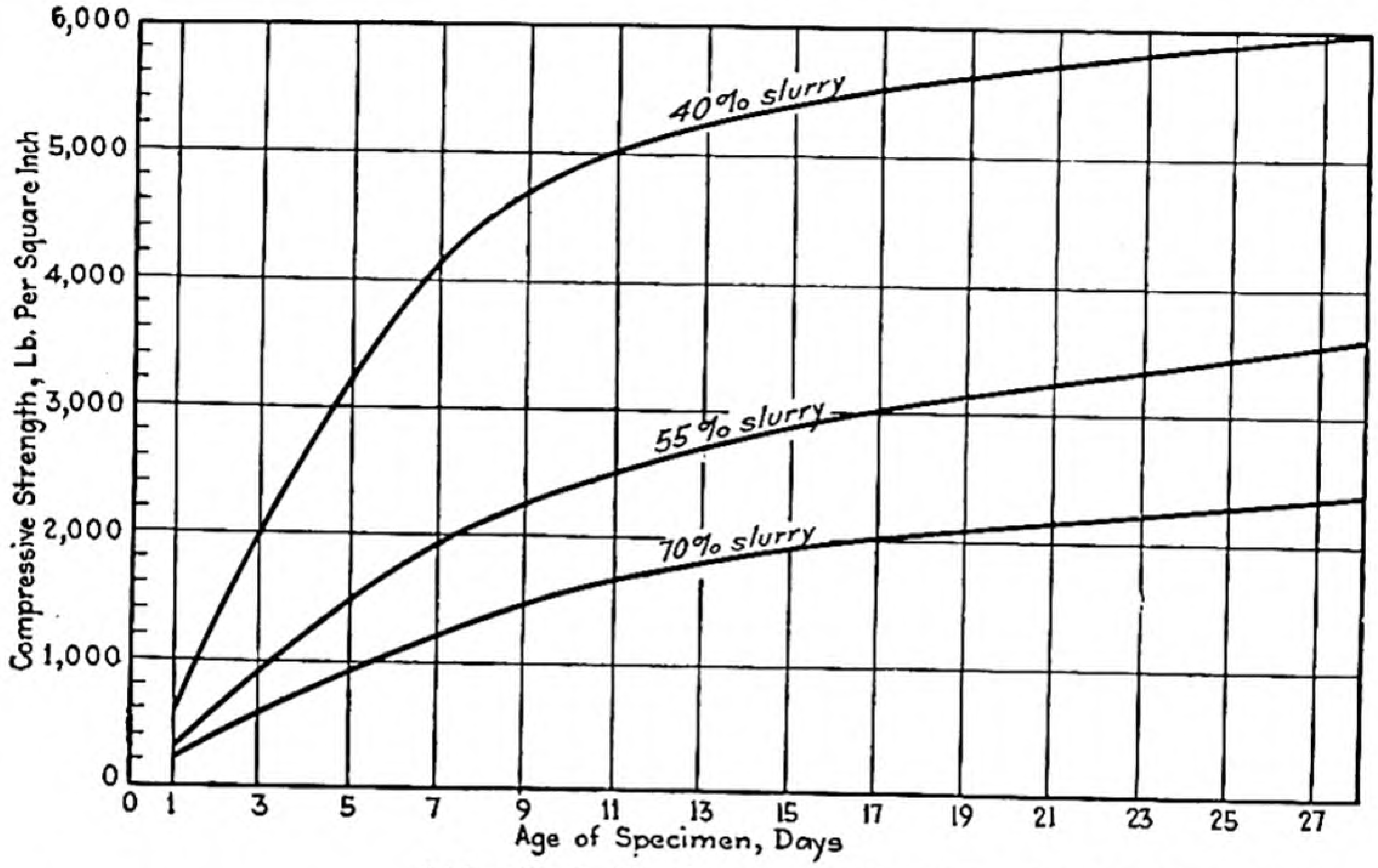
Permeability of Cement Plugs Formed under Deep-well Conditions.—Cement is used in wells primarily as a means of excluding water. If it is to achieve its purpose, the resulting cement plugs should be dense and impermeable. Studies of the permeability of neat cements, formed under various conditions, indicate that the permeability is diminished by fine grinding of the cement and is increased by water dilution of the slurry. Where excessive amounts of water are used in slurrifying the cement and there is time for setting of the cement particles before the initial set occurs, the upper part of the cement plug will be more permeable than the denser, lower part. A cement plug is more permeable during the first few days after it is formed, than later when hydration has progressed further. High ground temperatures hasten this action and tend to form plugs that quickly attain a high degree of impermeability. Actual measurements of cement permeability in specimens set and cured under the most advantageous conditions indicated permeabilities of less than 1 millidarcy. High water ratios may produce cements having permeabilities as great as 20 millidarcys.

Effect of Loss of Water to the Formation on Properties of Cement.—Under the high hydrostatic pressures existing in deep-well operations, water from the cement slurry may be forced prior to the initial set into the more permeable strata to which it has access through the wall of the well. The cement particles do not penetrate the formation to any great extent, but accumulate as a filter cake on the wall of the well. More water is filtered out of the cement in this way where it is in contact with highly permeable sand, sandstone and limestone strata than where it is in contact with less permeable clays and shales. As a result, differences in the water content of the slurry develop in different parts of the cement plug and lead to variations in setting time and ultimate strength of the cement in different horizons. If excess amounts of water exist in the slurry opposite shale horizons, local settling of cement particles therefrom may leave water pockets or discontinuities in the cement plug (see Fig. 203).

Volume Changes in the Setting of Cement.—When cement slurry comes to rest in the well, any excess water beyond a certain critical percentage tends to separate from the cement and is likely to be segregated in the form of water pockets in the cement column. This means that the volume of the set cement will be less than the original volume of the slurry. The settling tendency of the cement particles increases with the amount of water in excess of the critical amount and with the size of the cement particles. In laboratory tests with some slurries of high water content (70 per cent) and low specific surface (1,206 sq. cm. per gram) the hardened cement had a volume of only 77.6 per cent of the slurry from which it was formed. Slurries composed of 35 or 40 per cent water and cement of average specific surface

(1,400 to 1,600 sq. cm. per gram) suffer very little volume loss on setting and cements of high specific surface have critical water ratios in excess of 50 per cent.

Influence of Age and Storage Conditions on Setting Time of Cement.—Portland cement in storage inevitably undergoes a certain change in chemical composition that greatly alters its setting time. This is due to hydrolyzing of the lime as a result of contact with moisture in the air. This change operates to prolong the necessary setting time. Certain cements stored in a dry room for a period of 6 months have increased their setting times from 2 to 5 hr. The rate of change is, of course, primarily influenced by the conditions attending storage. For uniformity in results, cement



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 203.—Influence of age and water content on compressive strength of neat cement mixtures.

should be purchased direct from the manufacturers or large bulk distributors in quantities that will not require prolonged storage. This is particularly important in moist climates. The place of storage should be as dry as conditions permit.

TYPES OF CEMENT USED IN OIL-WELL SERVICE*

A variety of different types of portland cement are used in oil-well service, the choice of one or another depending upon the conditions in the well and the character of use. They differ chiefly in chemical composition and fineness of grinding, these properties being largely responsible for variations in thickening rate, strength and resistance to adverse chemical environment. When one considers the wide variety of conditions with which the operator must deal, it becomes apparent that there can be no all-purpose cement. Efforts of manufacturers to develop cements especially adapted to meet different conditions have naturally resulted

* Much of the material used in this section was first published in a series of articles by the Author in *Petroleum Engr.* See particularly, issues of August and September, 1942.

in products having a considerable range of properties, especially since there are, as yet, no generally accepted standards.[32]

The process of manufacture may be regulated to produce a slow-setting cement or a rapid-setting cement, a high-early-strength cement, one that is resistant to the influence of sulphate ground waters or to high ground temperatures. Addition of highly colloidal bentonite produces "gel" cement, and fibrous substances may be added to permit of more effective use of cement in sealing highly permeable formations. The addition of suitable amounts of calcium carbonate produces an acid-soluble cement. In most localities, oil producers may choose one of a dozen or more different brands and types of oil-well cements and may specify different combinations of grind, composition, thickening time, hardening rate and resistance to different conditions likely to be encountered in use. Some cements used in oil-well service are not of portland type: for example, gypsum cement is useful for some purposes.

Some authorities suggest that all cements used in oil-well service—except a few used for special purposes—might conveniently be classified into four groups, the classification being based primarily on differences in thickening time; that is, time elapsed after mixing the cement slurry for it to reach a viscosity marking the limit of pumpability. A cement classified in one of these groups may, of course, be altered by adding an accelerating or retarding agent. These groups may be designated as follows:*

Group 1.—High-early-strength cements, not necessarily sulphate resistant though advantageously so, are intended primarily for use under shallow-well conditions, as in cementing surface strings of casing and for rush rig foundations and cellars. The thickening time of such cements is usually about 1 hr. They have a higher than normal content of tricalcium silicate (60 to 70 per cent) and are ground unusually fine (specific surface 2,400 to 2,800 sq. cm. per gram). Forty per cent slurries of such cements are capable of developing tensile strengths of 500 to 700 lb. per sq. in. after 3 days at 150°F., or compressive strengths of approximately ten times these amounts.

Group 2.—Construction cements (regular or standard portland cements) are prepared to meet less rigid specifications than cements in the other groups and are likely to present a wider range of critical properties. Products of different manufacturers have a thickening-time range of from 1 hr. 20 min. to 2 hr. 30 min. They usually contain a high percentage of tricalcium aluminate that makes them vulnerable to deterioration by contact with sulphate ground waters. Construction cements are of medium texture, ranging in specific surface from 1,500 to 1,900 sq. cm. per gram. They are capable of developing tensile strengths of from 500 to 800 lb. per sq. in. from 40 per cent slurry maintained at 150°F. for 3 days. Accelerators may advantageously be used to increase moderately the rate of hardening with this type of cement.

Group 3.—Oil-well cements having a thickening time of about 1 hr. 40 min. to 2 hr. 20 min. are useful in cementing operations in all but very deep wells where high temperatures must be contended with. They contain a lower than normal percentage of tricalcium aluminate and a higher than normal percentage of tricalcium aluminoferrite, and are usually sulphate resistant. In comparison with other types of cement, they are coarsely ground, having a specific surface ranging from 1,100 to 1,900 sq. cm. per gram. Forty per cent slurries of such cement develop a tensile strength of 400 to 650 lb. per sq. in. after 3 days at 150°F.

Group 4.—High-temperature or retarded cements are made particularly for use under deep-well conditions where high temperatures and pressures are encountered, or where large amounts of cement must be mixed and placed in one operation. This type of cement provides a safety factor beyond normal setting times, assuring that

* Torrey, P. D., Correcting Cement Failures, *International Oil*, October, 1940, pp. 24–35.

the slurry will remain fluid and pumpable where unforeseen delays and interruptions in mixing or placement of the cement are likely to occur. High temperature and pressure tend greatly to shorten the thickening time and to offset this tendency; the cement is made to meet a thickening-time specification of more than 2 hr. 20 min. Sometimes the thickening time is as great as 4 hr. or more. The material must usually also be sulphate resistant.[43] To meet such requirements, the cement is coarsely ground (specific surface 1,400 to 1,600 sq. cm. per gram) and low in tricalcium aluminate content, and a chemical retarder, such as sodium tannate, may be added to the cement in carefully balanced amount to assure slow setting. Such cements are slow in developing full strength, the tensile strength of a specimen made from 40 per cent slurry being usually less than 500 lb. per sq. in. after 3 days at 150°F. One-day tensile strengths of specimens made from 40 per cent slurries at 100°F. are only about half those attained by high-early-strength cements.

Gel Cement.—For some purposes, such as sealing fissures or crevices sometimes encountered in drilling, or restoring lost circulation in cavernous formations, finely ground bentonite (Aquagel) may be added to cements of portland type. The amount of bentonite to use will vary with the ratio of water used in the cement slurry, but will range from ½ to 2 lb. per sack of cement for 40 to 70 per cent slurries. The bentonitic material is preferably mixed with the water to be used in preparing the cement slurry, and is circulated through a pump for a time sufficient to assure complete hydration of the clay before mixing with the cement. Presence of the bentonite confers thixotropic properties on the cement slurry and tends to hold the cement particles in suspension in high-water-ratio slurries, increasing their plasticity and viscosity and reducing loss of water to the formation. Such a mixture has a high angle of repose, so that, when injected into crevices or cavities, it quickly builds up an impermeable barrier. Addition of bentonite to cement decreases the setting time by a small percentage, but in comparison with a neat cement slurry of the same consistency, the setting time is increased. Presence of as much as 3 lb. of bentonite per sack of cement does not materially influence the strength or permeability of the set cement.[41,48]

Fiber Cements.—In cementing highly permeable, fissured or cavernous formations that tend to absorb cement slurry and prevent formation of cement plugs of desired length, fibrous materials may be added, either to the dry cement or to the cement slurry. This is done for the purpose of closing the rock openings at the wall of the well, sufficiently to retain the cement in the well even though high hydrostatic heads may be imposed. Cottonseed hulls, shredded paper, mica flakes, asbestos fiber and sugar-cane fiber have been used for this purpose. A specially prepared organic cellulose filler marketed under the name of Jelflake is also available for this purpose.* This material is in the form of very thin, extremely strong flakes having a crinkled surface. Individual flakes are about 0.001 in. thick and range from ½ to 1 in. in diameter. The material is chemically inert and is not altered by contact with mud, water, oil or cement. From ¾ to 1¼ lb. of the filler is used per sack of cement with some bentonite. In one successful cementing operation, 800 lb. of flake filler and 30 sacks of finely ground bentonite were used with 1,000 sacks of portland cement.[14,36]

Acid-soluble Cement.—Portland cements are only partly soluble in hydrochloric acid, an impervious coating of silica gel quickly collecting on the cement surface to restrict further access of the acid. Addition of from 40 to 45 per cent of very finely ground, intimately mixed calcium carbonate (limestone) makes any cement readily soluble in 15 per cent hydrochloric acid, only a fine, silty residue remaining after the cement has been in contact with the acid about 10 min. Acid-soluble

* Marketed by Dowell, Inc.

cement finds use in a variety of oil-well operations, particularly in squeeze cementing with the purpose of sealing certain productive formations to produce from others in the same formation interval, with the expectation of later removing the cement from the sealed horizons by acid treatment. A temporary bridge may also be formed in a well with this material and quickly removed by acid treatment when it has served its intended purpose. In addition, it is claimed that acid-soluble cement is more durable in contact with sulphate or chloride ground waters, and sets more readily in the presence of oil than ordinary cements. Naturally, a cement containing so large a percentage of foreign material lacks the strength of uncontaminated cement (2,200 to 4,000 lb. per sq. in. compressive strength in from 1 to 7 days), but this does not prevent its use for many purposes. The thickening rate is not materially influenced by presence of the calcium carbonate. Treated bentonitic material up to 3 per cent may also be added to acid-soluble cement without noticeably influencing the effect of the acid in its subsequent solution and disintegration. In some operations, acid-soluble cements may be used to form only a part of a cement plug, in the interval where it is expected the cement must later be removed.[45]

Use of Sand-cement Mixtures in Wells.—Cement used in oil-well operations is nearly always a neat cement mixture in the preparation of which portland cement is gauged only with water; but for some purposes sand may advantageously be added. For example, in sidetracking and hole-straightening operations, the solid component of the slurry may be about one-third sand. Cement-sand mixtures are harder to drill than neat cement, so that the drilling tools are more readily deflected from the former hole. Construction grades of portland cement are ordinarily used for this purpose. Owing to absorption of water by the sand, more water is required to obtain comparable consistency and the thickening time is shortened. Compressive and tensile strengths are diminished by addition of sand and the porosity and permeability are increased. Rather coarse sand (−20 + 30 mesh) is preferably used.

Radioactive Cement.—Owing to inequalities in the diameter of well bores and fluid loss to highly permeable formations, the height to which the cement rises above the shoe of a water string is often a matter of uncertainty. Yet, it may be important to know this in order to be assured that the casing is properly protected, or to determine whether certain formations are free behind the pipe or permanently sealed off from access to the well. One method of determining the position of the top of the cement plug involves mixing radioactive material, such as finely ground carnotite, with the first part of the cement pumped into the well. A gamma-ray survey (see page 643), made inside the casing at any later time, shows clearly the position of the radioactive material, with an abrupt change in the magnitude of the radioactivity log at the position of the top of the cement. In certain wells where 230 sacks of cement were used in cementing casing, about 25 lb. of finely ground carnotite containing about 10 per cent uranium oxide was distributed through the first few sacks of cement pumped into each well. Abnormally high radioactivity was apparent on the radioactivity logs of the wells for an interval of several hundred feet below the top of the cement plugs so treated.[10]

Gypsum Cement.—Occasionally cements of other than portland type will find use in oil-well service. One of these marketed under the trade name of Calseal, is a material made of gypsum and is sometimes called "gypsum cement." Unlike portland cement, it sets and hardens to full strength practically at the same time, usually in approximately 2 hr. after gauging with water. Slower and faster varieties are also available. Chemically, gypsum cement is partly hydrated calcium sulphate. On setting, it takes up additional water to form $CaSO_4.2H_2O$. It will set in contact with oil or salt water. It sets satisfactorily under high-temperature conditions or when subjected to continued agitation. The material develops a compressive strength

many times that of plaster of paris, another product of gypsum. Costing approximately three times as much as portland cement, Calseal is used primarily for operations involving formation of bridge plugs, shot tamps, regaining lost circulation and other uses where no very large amount of the material is required.

High-alumina Cement.—The so-called "high-alumina" cements are manufactured by sintering, or heating until molten, a mixture of limestone and bauxite. When cool, the resulting clinker is finely ground. The setting time for this type of cement is about the same as for portland cement but it develops strength much more rapidly after setting. After only 24 hr. it is as strong as ordinary portland cement after 28 days. High-alumina cements would probably find greater use in oil-well service if it were not for their high cost.

Iron Oxide Cement.—Cements prepared in the same way as portland cement but using hematite (iron ore) in substitution for clay or shale are called "iron oxide" cements. The resulting product has an unusually high iron oxide and low alumina content and is especially resistant to the destructive effects of saline waters. The slurry has unusually high specific gravity and is rather slow in setting and hardening, but forms a strong, hard cement.

Specifications and Tests Applied to Cements Used in Oil-well Service

For best results, cement used in oil-well service should, when slurrified with a suitable percentage of water, have a high degree of fluidity for such time as is necessary to force it into its intended position in the well. It should not take its initial set before this time has elapsed. It should then be capable of setting to form a dense, impermeable mass without loss of volume. It should harden rapidly and attain high early strength and it should be resistant to the disintegrating influences of alkaline sulphates frequently present in deep-seated ground waters. There is no one cement that will fulfill all of these requirements under all conditions that may be imposed in oil-well service. The oil producer must usually choose among a dozen or more different types of cement available to him and will ordinarily select the one that seems best able to develop the desired qualities under the conditions presented in the well where it is to be used.

For many purposes on oil-producing properties, ordinary construction cements of portland type are appropriate and, for these, the specifications approved by the American Society for Testing Materials are the best guide. Specifications adopted by the A.S.T.M. in 1941 (A.S.T.M. Designation 2-150-41) recognize five types of portland cement:[28]

Type I. For use in general concrete construction when the special properties specified for types II, III, IV and V are not required.

Type II. For use in general concrete construction exposed to moderate sulphate action, or where moderate heat of hydration is required.

Type III. For use when high early strength is required.

Type IV. For use when a low heat of hydration is required.

Type V. For use when high sulphate resistance is required.

The several types of cement, thus classified, are required to conform with the specifications given in Table XXXVII.

Because cement used in oil-well operations is subjected to higher temperatures, is necessarily gauged with a larger percentage of water and is subjected to more agitation prior to setting than cement used in surface construction work, it is found that the specifications and tests prescribed by the A.S.T.M. are not altogether appropriate and do not completely define the desirable properties or the methods for

determining them. A committee of the A.P.I. has, during recent years, been studying the conditions of use of cements in oil-well service and has proposed certain additional or alternate tests designed to indicate the suitability of cement for oil-well purposes.[31] A tentative code has been proposed and some of the tests suggested have already attained wide use in the petroleum industry and may be regarded as a probable basis for the cement-testing code that the A.P.I.

TABLE XXXVII.—PHYSICAL AND CHEMICAL SPECIFICATIONS FOR PORTLAND CEMENTS AS PRESCRIBED BY THE AMERICAN SOCIETY FOR TESTING MATERIALS

	Type I	Type II	Type III	Type IV	Type V
Silicon dioxide (SiO_2), min., % §	.....	21.0	.....	.....	24.0
Aluminum oxide (Al_2O_3), max., % §	.....	6.0	.....	.....	4.0
Ferric oxide (Fe_2O_3), max., % §	.....	6.0	.....	6.5	4.0
Magnesium oxide (MgO), max., % §	5.0	5.0	5.0	5.0	4.0
Sulphur trioxide (SO_3), max., % §	2.0	2.0	2.0	2.0	2.0
Loss on ignition, max., % §	3.0	3.0	3.0	3.0	3.0
Insoluble residue, max., % §	.75	.75	.75	.75	.75
Ratio of Al_2O_3 to Fe_2O_3	.....	.7 to 2.0	.....	.....	.7 to 2.0
Tricalcium silicate ($3CaO.SiO_2$),* max., %	.....	50.	.....	35.	
Dicalcium silicate ($2CaO.SiO_2$),† min., %	.....	.....	.....	40.	
Tricalcium aluminate ($3CaO.Al_2O_3$),‡ max., %	.....	8.	15.	7.	5.
Fineness, specific surface, sq. cm. per gram:					
Average value, min.‖	1,600	1,700	.....	1,800	1,800
Minimum value, one sample	1,500	1,600	.....	1,700	1,700
Soundness:					
Autoclave expansion, max., %¶	.50	.50	.50	.50	.50
Time of setting (alternate methods):					
Gilmore test:**					
Initial set, min., not less than	60	60	60	60	60
Final set, hr., not more than	10	10	10	10	10
Vicat test:					
Initial set, min., not less than	45	45	45	45	45
Final set, hr., not more than	10	10	10	10	10
Tensile strength, lb. per sq. in.:**					
1 day, not less than	.....	.....	275		
3 days, not less than	150	125	375		
7 days, not less than	275	250	.....	175	175
28 days, not less than	350	325	.....	300	300
Compressive strength, lb. per sq. in.:††					
1 day, not less than	.....	.....	1,300		
3 days, not less than	1,000	750	3,000		
7 days, not less than	2,000	1,500	.....	800	1,000
28 days, not less than	3,000	3,000	.....	2,000	2,200

* Tricalcium silicate = $(4.07 \times \%\ CaO) - (7.60 \times \%\ SiO_2) - (6.72 \times \%\ Al_2O_3) - (1.43 \times \%\ Fe_2O_3) - (2.85 \times \%\ SO_3)$.

† Dicalcium silicate = $(2.87 \times \%\ SiO_2) - (0.754 \times \%\ 3CaO.SiO_2)$.

‡ Tricalcium aluminate = $(2.65 \times \%\ Al_2O_3) - (1.69 \times Fe_2O_3)$.

§ Chemical analyses of cements must be made in accordance with A.S.T.M. "Standard Methods of Chemical Analysis of Portland Cement" (Designation C-114-40).

‖ Fineness test must be made in accordance with A.S.T.M. "Tentative Method of Test for Fineness of Portland Cement by Means of Turbidimeter" (Designation C-115).

¶ Tests for soundness must be made in accordance with A.S.T.M. "Tentative Method of Test for Autoclave Expansion of Portland Cement" (Designation C-151).

** Tests for setting time and tensile strength must be made in accordance with A.S.T.M. "Standard Methods of Sampling and Physical Testing of Portland Cement" (Designation C-77).

†† Compression strength tests must be made in accordance with A.S.T.M. "Tentative Method of Test for Compressive Strength of Portland Cement Mortars" (Designation C-109).

will eventually adopt. Following are the special tests that have been proposed to measure the essential qualities of cements to be used in oil-well service.[42]

Sieve Test.—This test is designed to disclose the presence of lumps and foreign material and to provide a clean sample for further testing. A 30-mesh screen 8 in. in diameter is used to segregate a 2,000-gram sample. Substantially all of the sample should pass through the 30-mesh screen.

Ring Test.—This is a simple and rapid procedure for comparing the relative fluidities of cement slurries. The apparatus used is a brass cylinder, 1⅝ in. in inside diameter and 2 in. high, with a wall thickness about ⅛ in., and a glass plate at least 12 in. square. A 200-gram sample of the cement to be tested is weighed and the required amount of water to form a slurry of the water percentage considered appropriate is mixed with the cement by agitation in a closed-top glass jar. The dry cement is poured into the water and the jar is shaken vigorously for 2 min. The brass cylinder is placed in an upright position on the center of the glass plate and is then filled quickly with slurry to slightly above the top. The slight excess of slurry is scraped off with a spatula or straightedge, throwing the excess cement to the outer edge of the glass plate. The cylinder is promptly lifted with a steady, upward motion, permitting the slurry to flow out through the bottom opening of the brass ring, over the surface of the glass plate, forming a smooth, round "pat." The diameter of the pat, measured to the nearest sixteenth of an inch, is taken as a measure of the fluidity of the slurry.

A cement slurry is considered to be of proper fluidity for pumping when it forms a pat having a diameter of 7½ in. in 1 min. It is proposed that this be regarded as a working standard of fluidity and that whatever proportions of water and cement are necessary to meet this requirement in the ring test shall be the proportions used in mixing cement slurry in the field. Some operators and cement technologists have expressed dissatisfaction with this test, believing that it does not produce results that are necessarily the best guide in determining the proper percentage of water in field-mixed slurries. Slight differences in the manner of lifting the ring to release the cement will produce differences in the result. It is also claimed that initial setting time and thickening-time tests provide an equally good index of pumpability. Nevertheless, the ring test has the advantage of simplicity and is widely used by operators in some regions.

Thickening-time Test.—This test is designed to indicate the allowable time, after a cement is mixed with water, before the slurry increases in viscosity to such a degree that it is no longer pumpable. It requires use of a thickening-time tester or consistometer, incorporating a stirring apparatus, means of temperature control, and means of continuously indicating values for relative viscosity of the slurry under test. Two types of instruments designed for this purpose have found wide use in the petroleum industry: (1) the ice-cream-freezer type of thickening-time tester, developed by technologists of the Standard Oil Co. of Calif., and used almost exclusively by California oil producers, and (2) a consistometer used by the Halliburton Oil Well Cementing Co. and many petroleum producers of the Mid-Continent and Gulf Coast regions of the United States. Both of these instruments serve the same purpose and provide for conduct of the thickening-time test in much the same way, but express the viscosity of the thickening cement slurry in different units and prescribe different temperature conditions. An improved type of consistometer provides means for controlling the pressure to which the slurry is subjected, as well as the temperature.

The Standard Oil Co. of Calif. type of tester resembles an ice-cream freezer in internal construction and is of the nature of a torsion viscosimeter. The instrument comprises a cylindrical cup in which a centrally supported spindle equipped with projecting rabbles is revolved by a worm gear, driven by an electric motor. An

electrically heated water bath surrounds the cup. A wire attached tangentially to the rim of the cup applies tension to the indicating mechanism of a spring balance, which provides a direct measure of the viscosity of the slurry in the cup. In making a test, the prepared slurry is poured into the tester cup, filling it to a prescribed level, the slurry and water bath being at an initial temperature of 80°F. Power is applied, causing the spindle to revolve at a speed of 60 r.p.m. Rotation continues at this speed for 19 min., meanwhile applying heat to the water bath so that the temperature rises at the rate of 1°F. per min. The temperature is increased at this rate until a temperature of 140°F. is reached, and thereafter is maintained at this value until the test is completed. After 19 min., the rotational speed of the spindle is reduced to 14.5 r.p.m. Observations of the pull exerted by the thickening cement on the spring balance are made at 10-min. intervals and the elapsed time from initial wetting of the cement to attainment of a 40-oz. pull is taken as the thickening time of the slurry. For record purposes, however, the test is continued until a 48- or 50-oz. pull is attained.

The consistometer seemingly preferred by Mid-Continent and Gulf Coast operators comprises two cylindrical cups, supported in a metal tank and surrounded by a thermostatically controlled bath. Each cup contains a revolving paddle, rotated by a worm gear driven by an electric motor, and is an independent and complete unit. Thus, two tests can be conducted simultaneously. As the paddles revolve at constant speed, the thickening cement slurry exerts a thrust that is transmitted through a movable drag head on the top of each cup to a lever arm, causing the latter to be deflected from its normal vertical position. The amount of deflection of the lever indicator at any time is thus a measure of the viscosity of the slurry, and a scale on which observations of the amount of deflection are made is calibrated to read directly in centipoises of absolute viscosity. By means of a thermoregulator and a 3-point switch, the water bath may be maintained at a constant temperature of either 100, 140 or 180°F. The test is conducted at any one of these temperatures that the operator may consider most appropriate, making observations of slurry viscosity at 10-min. intervals, until a reading of 10 (approximately 10,000 centipoises) is attained, which is regarded as the limit of pumpability.

The thickening-time test, as conducted with the aid of either of the above-described instruments, yields data from which a thickening-time curve for the slurry under test may be developed. With reference to this record and an estimate of the time necessary to mix and place the cement in a proposed operation, the interval of time remaining before the cement becomes unpumpable may be closely estimated. An effort is made to apply test temperatures that will accord as nearly as possible with the temperature conditions to which the slurry will be subjected during actual placement in the well.

With knowledge of the effect of pressure on the setting time of cement slurries and of the fact that very high pressures are applied in placing cement in deep wells, technologists in the employ of the Stanolind Oil & Gas Co. have developed a type of thickening-time tester in which slurry under test may be subjected to gradual increase in pressure as well as gradual increase in temperature. An effort is made to reproduce in the tester the pressure and temperature conditions to which the slurry will be subjected during placement in the well, meanwhile securing a record of slurry consistency.

Tensile-strength Tests.—Strength tests prescribed by the A.S.T.M. require the use of slurries containing much less water than is necessarily used in preparing slurries to be pumped into wells. The A.P.I. Committee on Oil Well Cements suggests comparable tests made with slurries of the water content actually used in oil-well service, curing specimens at a temperature comparable with that to which the cement will be subjected in the well. In preparing briquettes for testing, screened cement and water

in proper proportions are slurrified at a temperature of 80°F., poured into 12 greased molds supported on a greased plate, and allowed to set in a water bath at 150°F. After 4 or 5 hr., when the slurry has set, the briquettes should be removed from the molds and returned to the 150°F. bath to cure. Twenty-four hours after the briquettes were poured, four are removed from the water bath, one at a time, and broken in a tensile-strength-testing machine, applying the load at the rate of 600 lb. per min. Three- and seven-day strengths are determined with other briquettes in the same manner. The breaking strength of each briquette is recorded and the average for each group of four is computed. Briquettes containing air bubbles or otherwise obviously faulty, or differing in breaking strength by more than 15 per cent from the average, should be rejected and not used in computing averages. Most cements having an initial fluidity prescribed as standard for the ring test develop 1-day tensile strengths in excess of 300 lb. per sq. in. and the 3-day specimens should show a substantial increase in strength.

Most cement technologists prefer compression tests to tension tests as a measure of the strength of cement, claiming that the results of tensile-strength tests are too variable. However, the equipment necessary for making tests of compressive strength is costly and not usually available in oil-field laboratories. Compressive strengths of neat cements will be, roughly, ten times the tensile strengths.

Foam Test.—When slurrified, some cements, though normal in other respects, develop abnormal amounts of stabilized foam which may cause trouble in the mixing and placement of the slurry. As a measure of this tendency, a simple test has been devised. Fifty milliliters of water are placed in a test tube 1 in. in diameter and 8 in. long, and to this 30 grams of cement are added. The water and cement are shaken vigorously in the tube for 1 min. with the end of the tube closed, and the inner wall of the tube is then washed down with a small amount of water. Any foam that may be present floats on the water and its depth may be measured. Cement that produces more than ½ in. of foam may cause difficulty in handling in the field-mixing and pumping equipment.

PLANNING A CEMENT JOB

Before a cementing operation in a well is attempted, the work should be carefully planned in order to ensure its successful completion. The size of casing to be cemented will probably have been determined by the drilling program planned for the well, and a hole of appropriate diameter to receive this size of pipe will have been drilled. The landing depth of the shoe of a water string should be carefully selected so that, if possible, it may rest in a stratum impervious to the passage of water. The desirable length for the cement plug should be determined and the necessary amount of cement calculated to form a plug of this length for the size of casing to be used in the size of hole drilled. The physical conditions presented should be carefully studied. Important considerations will include the temperature and pressure to which the cement will be subjected prior to setting and the possibility of contamination of the cement with saline ground water, mud or oil, or of its being subjected to agitation by strong flows of gas or water during the setting period. The condition of the bottom and walls of the well and the position of the casing will also be matters of concern; and there must be assurance

of free circulation between the casing and the walls of the well on application of such pressure as will be possible with the pumping equipment available. If any one of these factors is unfavorable, it may defeat the purpose of the work unless its influence is considered and preparations made to counteract it at the proper time.

The cement to be used in the work should be sampled systematically and a portion of the sample subjected to such tests as will be necessary to give assurance that it conforms with essential specifications. The proper percentage of water to be used in the field-mixed slurry may be determined by the ring test. The initial setting time and thickening time of the cement under the temperature and pressure conditions to which it will be subjected during placement should be determined when mixed in proper ratio with a sample of the water to be used in preparing the slurry in the field. Briquettes may be prepared and tested to determine tensile strength. The cement may be subjected to an autoclave test to determine whether or not it is unsound. Frothing tendencies will be observed. If possible, a sample of the well fluid from a depth in the well near the proposed shutoff point will be secured and mixed with a sample of the cement slurry to determine the influence of any dissolved salts that may be present on the setting time.

As explained in an earlier section, the size of hole drilled will be from 2 to 6 in. larger in diameter than the nominal diameter of the casing to be cemented in it. However, the effective clearance will be somewhat reduced by accumulation of a mud sheath on the wall of the well, the thickness of which will depend upon the condition of the drilling fluid used, the permeability of the formation exposed in the wall of the well and the extent to which it has absorbed water from the well fluid. Often the bore of the well will be locally enlarged by the erosional effect of the drilling fluid as it flows under high pressure and velocity through the discharge ports of the drilling bit. Irregularities of this kind are difficult to evaluate in estimating the volume of cement necessary to fill the well through a given interval, but may be best appraised on the basis of a caliper survey of the well (see page 661).

It is important that the diameter of the hole be proportioned to that of the casing, not only to afford sufficient space for the cement to form a continuous cement plug of proper thickness, but also to provide proper ascending velocity for the cement slurry. The ascending velocity of the fluid outside of the casing should be greater than that of the descending column within. If the diameter of the hole is too great, the cement tends to settle and coagulate and perhaps attain its initial set before it is all displaced from the casing. Case[7] suggests the formula

$$D^2 = 2d^2$$

for computing the diameter of hole to be drilled. In this formula D is the diameter of the hole and d the inside diameter of the casing. This gives the maximum diameter of the hole if the ascending velocity is to be greater than that of the descending velocity. The following values for D have been computed, with the aid of this formula, for different commonly used sizes of casing:

Diameter of Casing d, In.	Maximum Diameter of Well D, In.
12½	17.66
11	15.55
10	14.00
8¼	11.66
6¼	8.85

The length of the cement plug to be formed in the well will be determined by the objectives sought and the conditions presented. Where top water is to be excluded by placing a cement plug around the lower end of a column of casing, it is good practice to assume that the casing shoe will be set at a point below the bottom of the water-yielding formation and extend up above this point to an elevation above the top of the water-bearing interval. This is particularly desirable where it is sought to protect the casing from the corrosive effects of the water. Often such plugs will be many hundreds of feet long. Where there is possibility of movement of fluids outside of the casing from one stratum to another, it is often desirable to use a cement plug long enough to seal off both. Bottom-hole plugs must be long enough to provide ample contact with the formation to resist upward displacement by pressure of fluids from below. The greater the length of the cement plug, the greater will be the security afforded against penetration of fluids through or around the plug. A factor of safety is thus afforded to guard against failure of the plug to serve its intended purpose by reason of local crevices, shrinkage cavities, air bubbles, mud occlusions and other irregularities that may permit restricted fluid movement. Sometimes surface strings are cemented by filling the annular space about them all the way to the surface, thus securely anchoring the pipe to the formation, providing against upward movement under the influence of pressure from below or downward settling due to the weight of interior casings suspended from the casing head.

The volume of cement necessary to form a cement plug of desired length for a given average diameter of hole and size of casing should be carefully estimated. This, of course, can readily be computed by multiplying the proposed length of the plug by the cross-sectional area of the annular space. On the assumption that one sack of cement will

TABLE XXXVIII.—AMOUNT OF CEMENT NECESSARY TO FORM CEMENT PLUGS ABOUT CASINGS OF VARIOUS SIZES IN WELLS OF DIFFERENT DIAMETERS*†

Style	Outside diameter, in.	Weight per foot complete	Casing diameter		Number of sacks of neat cement to fill 100 lin. ft., outside various sizes of casing in various sizes of holes																									Number of sacks of neat cement to fill 100 lin. ft. on the inside of casing
					Diameter of hole, in.																									
			External	Internal	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	
A.P.I.	4¾	16	4.750	4.082	7	13	20	29	39	48	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	8
Non A.P.I.	5	15	5.000	4.408	5	12	19	28	37	48	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	10
Non A.P.I.	5	18	5.000	4.276	5	12	19	28	37	48	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	9
Non A.P.I.	5	21	5.000	4.154	5	12	19	28	37	48	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	9
Non A.P.I.	5½	17	5.500	4.892	...	9	17	25	35	46	56	67	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	12
Non A.P.I.	5½	20	5.500	4.778	...	9	17	25	35	46	56	67	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	11
A.P.I.	5¾	14	5.750	5.290	...	8	15	24	33	44	56	67	83	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	14
A.P.I.	5¾	17	5.750	5.190	...	8	15	24	33	44	56	67	83	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	13
A.P.I.	5¾	19.5	5.750	5.090	...	8	15	24	33	44	56	67	83	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	13
A.P.I.	5¾	22.5	5.750	4.990	...	8	15	24	33	44	56	67	83	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	12
A.P.I.	6⅝	20	6.625	6.049	...	...	10	19	28	39	50	63	77	91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	18
A.P.I.	6⅝	24	6.625	5.921	...	...	10	19	28	39	50	63	77	91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	17
A.P.I.	6⅝	26	6.625	5.855	...	...	10	19	28	39	50	63	77	91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	17
A.P.I.	6⅝	28	6.626	5.791	...	...	10	19	28	39	50	63	77	91	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	17
A.P.I.	7	20	7.000	6.456	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	21
A.P.I.	7	22	7.000	6.398	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	20
A.P.I.	7	24	7.000	6.336	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	20
A.P.I.	7	26	7.000	6.276	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	20
A.P.I.	7	28	7.000	6.214	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	19
A.P.I.	7	30	7.000	6.154	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	19
Non A.P.I.	7	43	7.000	5.736	...	...	7	16	25	36	48	59	71	91	100	...	...	...	...	...	...	...	...	...	...	...	...	...	...	16
A.P.I.	7⅝	26.40	7.625	6.969	...	...	...	11	21	31	42	56	67	84	100	111	...	...	...	...	...	...	...	...	...	...	...	...	...	24
A.P.I.	7⅝	29.70	7.625	6.875	...	...	...	11	21	31	42	56	67	84	100	111	...	...	...	...	...	...	...	...	...	...	...	...	...	24
A.P.I.	7⅝	33.70	7.625	6.765	...	...	...	11	21	31	42	56	67	84	100	111	...	...	...	...	...	...	...	...	...	...	...	...	...	23
A.P.I.	8⅛	28	8.125	7.485	...	...	...	...	17	22	39	50	63	77	91	111	...	...	...	...	...	...	...	...	...	...	...	...	...	28
A.P.I.	8⅛	32	8.125	7.385	...	...	...	...	17	22	39	50	63	77	91	111	...	...	...	...	...	...	...	...	...	...	...	...	...	27
A.P.I.	8⅛	35.5	8.125	7.285	...	...	...	...	17	22	39	50	63	77	91	111	...	...	...	...	...	...	...	...	...	...	...	...	...	26
A.P.I.	8⅛	39.5	8.125	7.185	...	...	...	...	17	22	39	50	63	77	91	111	...	...	...	...	...	...	...	...	...	...	...	...	...	26
A.P.I.	8⅝	28	8.625	8.017	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	32
A.P.I.	8⅝	32	8.625	7.921	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	31
A.P.I.	8⅝	36	8.625	7.825	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	30

A.P.I.	8⅝	38	8.625	7.775	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	29
A.P.I.	8⅝	43	8.625	7.651	...	...	...	...	13	23	35	48	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	...	...	29
A.P.I.	9	34	9.000	8.290	...	...	...	...	...	20	31	44	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	...	34
A.P.I.	9	38	9.000	8.196	...	...	...	...	...	20	31	44	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	...	33
A.P.I.	9	40	9.000	8.150	...	...	...	...	...	20	31	44	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	...	32
A.P.I.	9	45	9.000	8.032	...	...	...	...	...	20	31	44	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	...	31
A.P.I.	9⅝	36	9.625	8.921	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	40
Non A.P.I.	9⅝	38	9.625	8.885	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	40
A.P.I.	9⅝	40	9.625	8.835	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	38
Non A.P.I.	9⅝	42	9.625	8.799	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	38
A.P.I.	9⅝	43.5	9.625	8.755	...	...	...	...	...	14	26	39	53	67	83	100	111	...	...	...	...	...	...	...	...	...	...	...	...	37
A.P.I.	10¾	40.5	10.750	10.050	...	...	...	...	...	...	14	26	40	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	50
A.P.I.	10¾	45.5	10.750	9.950	...	...	...	...	...	...	14	26	40	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	48
A.P.I.	10¾	51	10.750	9.850	...	...	...	...	...	...	14	26	40	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	48
A.P.I.	10¾	55.5	10.750	9.760	...	...	...	...	...	...	14	26	40	56	71	83	100	125	...	...	...	...	...	...	...	...	...	...	...	48
A.P.I.	11¾	47	11.750	11.000	...	...	...	...	...	...	...	15	29	44	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	59
A.P.I.	11¾	54	11.750	10.880	...	...	...	...	...	...	...	15	29	44	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	59
A.P.I.	11¾	60	11.750	10.772	...	...	...	...	...	...	...	15	29	44	59	77	91	111	125	...	...	...	...	...	...	...	...	...	...	59
Non A.P.I.	13	40	13.000	12.438	...	...	...	...	...	...	...	...	...	28	44	59	77	91	111	143	...	...	...	...	...	...	...	...	...	77
Non A.P.I.	13	45	13.000	12.360	...	...	...	...	...	...	...	...	...	28	44	59	77	91	111	143	...	...	...	...	...	...	...	...	...	77
Non A.P.I.	13	50	13.000	12.282	...	...	...	...	...	...	...	...	...	28	44	59	77	91	111	143	...	...	...	...	...	...	...	...	...	77
Non A.P.I.	13	54	13.000	12.220	...	...	...	...	...	...	...	...	...	28	44	59	77	91	111	143	...	...	...	...	...	...	...	...	...	71
A.P.I.	13⅜	48	13.375	12.715	...	...	...	...	...	...	...	...	...	23	39	56	71	91	111	125	143	...	...	...	...	...	...	...	...	83
A.P.I.	13⅜	54.5	13.375	12.615	...	...	...	...	...	...	...	...	...	23	39	56	71	91	111	125	143	...	...	...	...	...	...	...	...	77
A.P.I.	13⅜	61	13.375	12.515	...	...	...	...	...	...	...	...	...	23	39	56	71	91	111	125	143	...	...	...	...	...	...	...	...	77
A.P.I.	13⅜	68	13.375	12.415	...	...	...	...	...	...	...	...	...	23	39	56	71	91	111	125	143	...	...	...	...	...	...	...	...	77
A.P.I.	16	55	16.000	15.375	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
A.P.I.	16	65	16.000	15.250	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
Non A.P.I.	16	70	16.000	15.198	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
A.P.I.	16	75	16.000	15.125	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
A.P.I.	16	84	16.000	15.010	...	...	...	...	...	...	...	...	...	...	...	...	33	53	71	91	111	143	...	...	...	...	...	...	...	111
A.P.I.	18⅝	78	18.625	17.855	...	...	...	...	...	...	...	...	...	...	...	...	...	...	26	48	67	91	111	143	...	...	...	...	...	167
A.P.I.	18⅝	87.5	18.625	17.755	...	...	...	...	...	...	...	...	...	...	...	...	...	...	26	48	67	91	111	143	...	...	...	...	...	167
A.P.I.	18⅝	96.5	18.625	17.655	...	...	...	...	...	...	...	...	...	...	...	...	...	...	26	48	67	91	111	143	...	...	...	...	...	167
Non A.P.I.	20	90	20.000	19.190	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	42	63	91	111	143	167	...	...	...	200
A.P.I.	21½	92.5	21.500	20.710	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	33	56	83	111	125	167	...	...	200
A.P.I.	21½	103	21.500	20.610	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	33	56	83	111	125	167	...	...	200
A.P.I.	21½	114	21.500	20.510	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	33	56	83	111	125	167	...	...	200
A.P.I.	24½	100.5	24.500	23.750	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	37	63	91	125	143	250
A.P.I.	24½	113	24.500	23.650	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	37	63	91	125	143	250

NOTE:—The above are theoretical figures, no allowance being made for variations in size of hole.
* Courtesy of Spang, Chalfant & Co., Inc., Pittsburgh, Pa.
† Calculations based on assumption that one sack of neat cement, after setting, fills 1.1 cu. ft.

form 1.1 cu. ft. of set cement, we may then compute the number of sacks of cement necessary. A convenient formula for computing the quantity of cement necessary for a planned operation in which a neat cement plug is to be formed in a well about the lower end of a column of casing is that proposed by Scott:*

$$Q = \frac{F \times (d_1^2 - d^2) \times 0.005454}{1.1}$$

In this formula, F is the number of linear feet to be filled in the annular space outside of the casing; d_1 is the diameter of the hole in inches; d is the outside diameter of the casing in inches; and Q is the number of sacks of cement required. Another useful formula for computing the volume of cement necessary is given by Torrey:[24]

$$\text{Linear feet of annular space filled by 1 sack of cement} = \frac{201.68076}{D^2 - d^2}$$

Here D is the diameter of the hole and d represents the outside diameter of the casing.

The amount of cement necessary to fill a well or a column of casing for a given number of linear feet may be found by the expression:

$$Q = \frac{0.005454d^2 \times F}{1.1}$$

In this formula, d is the diameter of the well or the inside diameter of the casing to be filled and F is the number of linear feet to be filled.

On the assumption that one sack of cement forms 1.1 cu. ft. of set cement in the well, Table XXXVIII has been prepared to indicate directly the amount of cement necessary per 100 lin. ft. of plug, for different combinations of hole diameter and casing size. The number of sacks of cement necessary to fill 100 lin. ft. of casing of various sizes is also given. Table XXXIX will also be found useful in quickly determining the volumetric capacities of different sizes of casing and tubing. Such data are useful in estimating the linear feet of pipe occupied by a given volume of slurry during a cementing operation.

The amount of cement used in a cementing job will depend chiefly upon the size of the casing. Table XL shows the average quantities of cement used in 183 different cementing operations on different sizes of casing in the California fields. It will be seen that the quantity of cement used increases with the diameter of the casing and that the time occupied in displacing the cement from the casing ranges from 35 to 45 min. Average final pump pressures range from 550 to upward of 800 lb. As many as 2,000 sacks of cement are used in some cases where large-

* Scott, B. H., Difficult Conditions Met by Modern Cementing Systems, *Oil Field Eng.*, October, 1928, pp. 23–31.

TABLE XXXIX.—VOLUMETRIC CAPACITIES OF TUBING AND CASINGS OF DIFFERENT WEIGHTS AND SIZES*

Style	Nominal size, in.	Weight per foot complete	Tubing diameters		Capacity bbl. per 100 ft.	Capacity lin. ft. per barrel
			External	Internal		
†A.P.I.	1¼	2.40	1.660	1.380	.185	540.540
†A.P.I.	1½	2.90	1.900	1.610	.252	398.050
A.P.I.	2	4.60	2.375	1.995	.387	258.650
†A.P.I.	2	4.70	2.375	1.995	.387	258.650
A.P.I.	2½	6.40	2.875	2.441	.579	172.760
†A.P.I.	2½	6.50	2.875	2.441	.579	172.760
A.P.I.	3	9.20	3.500	2.992	.870	114.990
†A.P.I.	3	9.30	3.500	2.992	.870	114.990
A.P.I.	3	10.20	3.500	2.922	.829	120.570
A.P.I.	3½	9.50	4.000	3.548	1.223	81.777
†A.P.I.	3½	11.00	4.000	3.476	1.174	85.198
A.P.I.	4	12.60	4.500	3.958	1.522	65.710
†A.P.I.	4	12.75	4.500	3.958	1.522	65.710

Style	Outside diameter, in.	Weight per foot complete	Casing diameters		Capacity bbl. per 100 ft.	Capacity lin. ft. per barrel
			External	Internal		
A.P.I.	4¾	16.00	4.750	4.082	1.618	61.794
Non A.P.I.	5	15.00	5.000	4.408	1.888	52.980
Non A.P.I.	5	18.00	5.000	4.276	1.776	56.300
Non A.P.I.	5	21.00	5.000	4.154	1.676	59.656
Non A.P.I.	5½	17.00	5.500	4.892	2.325	43.014
Non A.P.I.	5½	20.00	5.500	4.778	2.218	45.091
A.P.I.	5¾	14.00	5.750	5.290	2.719	36.785
A.P.I.	5¾	17.00	5.750	5.190	2.617	38.216
A.P.I.	5¾	19.50	5.750	5.090	2.517	39.733
A.P.I.	5¾	22.50	5.750	4.990	2.419	41.342

Style	Outside diameter, in.	Weight per foot complete	Casing diameters		Capacity bbl. per 100 ft.	Capacity lin. ft. per barrel
			External	Internal		
A.P.I.	6⅝	20.00	6.625	6.049	3.554	28.134
A.P.I.	6⅝	24.00	6.625	5.921	3.406	29.362
A.P.I.	6⅝	26.00	6.625	5.855	3.330	30.028
A.P.I.	6⅝	28.00	6.625	5.791	3.258	30.697
A.P.I.	7	20.00	7.000	6.456	4.049	24.698
A.P.I.	7	22.00	7.000	6.398	3.976	25.148
A.P.I.	7	24.00	7.000	6.336	3.900	25.589
A.P.I.	7	26.00	7.000	6.276	3.826	26.135
A.P.I.	7	28.00	7.000	6.214	3.751	26.660
A.P.I.	7	30.00	7.000	6.154	3.679	27.181
Non A.P.I.	7	43.00	7.000	5.736	3.196	31.287
A.P.I.	7⅝	26.40	7.625	6.969	4.718	21.196
A.P.I.	7⅝	29.70	7.625	6.875	4.591	21.780
A.P.I.	7⅝	33.70	7.625	6.765	4.446	22.493
A.P.I.	8⅛	28.00	8.125	7.485	5.442	18.374
A.P.I.	8⅛	32.00	8.125	7.385	5.298	18.875
A.P.I.	8⅛	35.50	8.125	7.285	5.156	19.397
A.P.I.	8⅛	39.50	8.125	7.185	5.015	19.940
A.P.I.	8⅝	28.00	8.625	8.017	6.244	16.017
A.P.I.	8⅝	32.00	8.625	7.921	6.095	16.407
A.P.I.	8⅝	36.00	8.625	7.825	5.948	16.812
A.P.I.	8⅝	38.00	8.625	7.775	5.872	17.029
A.P.I.	8⅝	43.00	8.625	7.651	5.687	17.585
A.P.I.	9	34.00	9.000	8.290	6.676	14.980
A.P.I.	9	38.00	9.000	8.196	6.525	15.325
A.P.I.	9	40.00	9.000	8.150	6.453	15.498
A.P.I.	9	45.00	9.000	8.032	6.267	15.957
A.P.I.	9⅝	36.00	9.625	8.921	7.731	12.935
Non A.P.I.	9⅝	38.00	9.625	8.885	7.669	13.040
A.P.I.	9⅝	40.00	9.625	8.835	7.583	13.188
Non A.P.I.	9⅝	42.00	9.625	8.799	7.521	13.296
A.P.I.	9⅝	43.50	9.625	8.755	7.446	13.430

Style	Outside diameter, in.	Weight per foot complete	Casing diameters		Capacity bbl. per 100 ft.	Capacity lin. ft. per barrel
			External	Internal		
A.P.I.	10¾	40.50	10.750	10.050	9.812	10.192
A.P.I.	10¾	45.50	10.750	9.950	9.617	10.398
A.P.I.	10¾	51.00	10.750	9.850	9.425	10.610
A.P.I.	10¾	55.50	10.750	9.760	9.254	10.807
A.P.I.	11¾	47.00	11.750	11.000	11.754	8.508
A.P.I.	11¾	54.00	11.750	10.880	11.499	8.696
A.P.I.	11¾	60.00	11.750	10.772	11.272	8.871
Non A.P.I.	13	40.00	13.000	12.438	15.028	6.654
Non A.P.I.	13	45.00	13.000	12.360	14.841	6.738
Non A.P.I.	13	50.00	13.000	12.282	14.654	6.824
Non A.P.I.	13	54.00	13.000	12.220	14.506	6.894
A.P.I.	13⅜	48.00	13.375	12.715	15.705	6.367
A.P.I.	13⅜	54.50	13.375	12.615	15.459	6.469
A.P.I.	13⅜	61.00	13.375	12.515	15.215	6.573
A.P.I.	13⅜	68.00	13.375	12.415	14.973	6.679
A.P.I.	16	55.00	16.000	15.375	22.964	4.355
A.P.I.	16	65.00	16.000	15.250	22.592	4.426
Non A.P.I.	16	70.00	16.000	15.198	22.437	4.457
A.P.I.	16	75.00	16.000	15.125	22.224	4.500
A.P.I.	16	84.00	16.000	15.010	21.886	4.569
A.P.I.	18⅝	78.00	18.625	17.855	30.969	3.229
A.P.I.	18⅝	87.50	18.625	17.755	30.626	3.265
A.P.I.	18⅝	96.50	18.625	17.655	30.279	3.303
Non A.P.I.	20	90.00	20.00	19.190	35.773	2.795
A.P.I.	21½	92.50	21.500	20.710	41.665	2.400
A.P.I.	21½	103.00	21.500	20.610	41.264	2.424
A.P.I.	21½	114.00	21.500	20.510	40.865	2.447
A.P.I.	24½	100.50	24.500	23.750	54.794	1.825
A.P.I.	24½	113.00	24.500	23.650	54.334	1.841

* Courtesy of Spang, Chalfant & Co., Inc., Pittsburgh, Pa.

† Upset tubing.

diameter casings are to be cemented and unusually long plugs must be formed.

TABLE XI.—DATA ON TYPICAL CEMENTING OPERATIONS IN THE CALIFORNIA FIELDS*

Size of casing, in.	Average length of string, ft.	Average amount of cement, sacks	Average time of displacement, min.	Average final pump pressure, lb. per sq. in.	Maximum casing length, ft.
6⅝	4,604	110	35.5	730	6,668
8⅝	4,886	318	38.5	830	5,934
9	3,282	330	36	625	5,679
11¾	3,107	410	45	614	4,714
13⅜	3,141	385	40	558	4,195

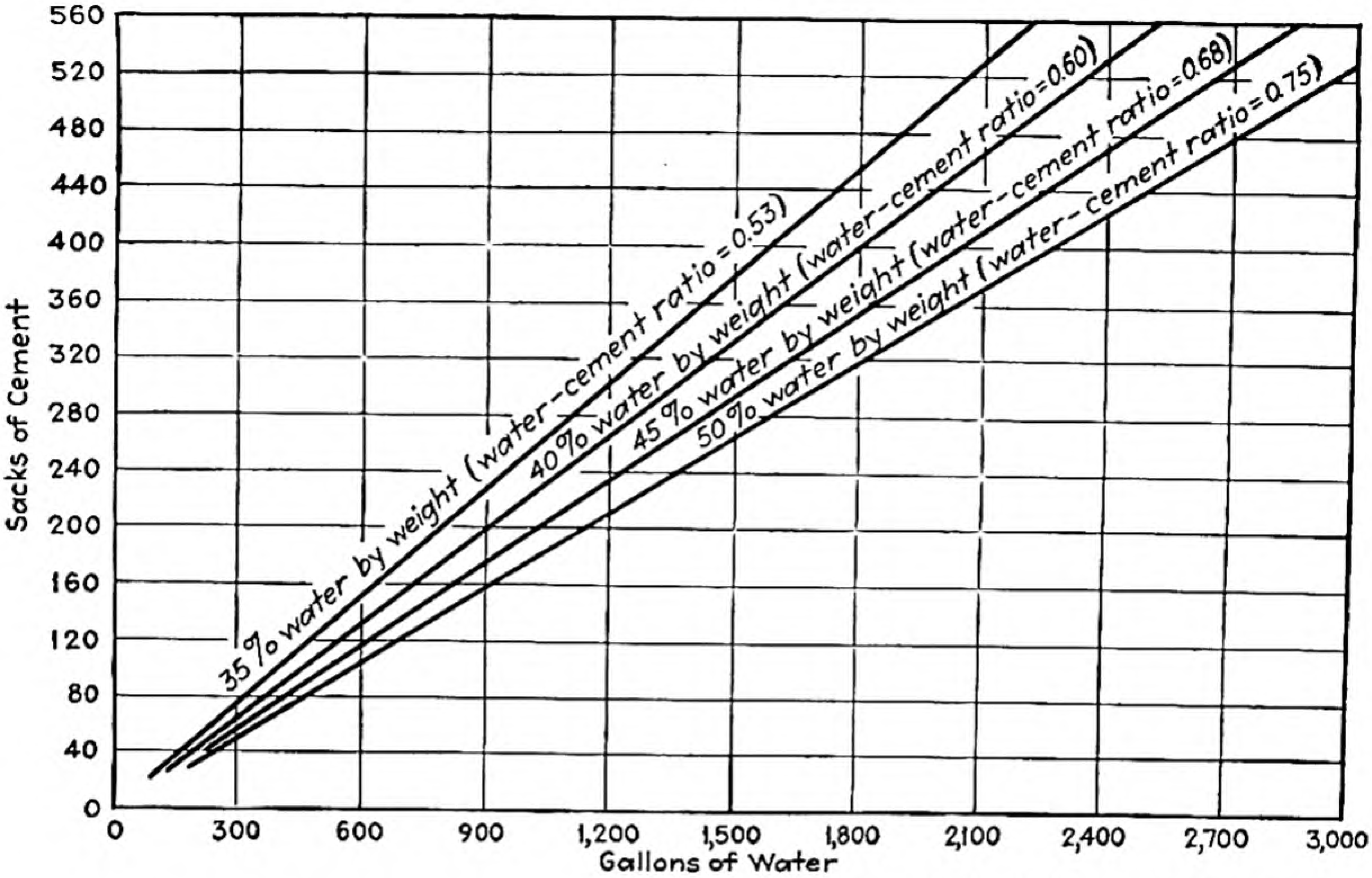
* Data collected by a committee of California operators and cement contractors.

It is convenient, in planning cementing operations, to have in mind certain constants expressing the relations between the weights and volumes of cement mixtures, and to have access to tables that simplify the work of calculating volumes to be filled. Portland cement varies somewhat in density, ranging from 3.10 to 3.23. A sack of cement weighing 94 lb. is estimated to have an average absolute volume of 0.484 cu. ft., or 829.44 cu. in. This represents the volume of the material less that of the pore space occluded within it. When mixed with water, the volume of the mixture will depend upon the percentage of water used in the mix.

In cement terminology, the percentage of water used in preparation of cement slurry is always a percentage of the weight of the dry cement—not a percentage of the weight of the mixture. Thus, a 40 per cent slurry contains 40 lb. of water for each 100 lb. of dry cement. The percentage of water used in slurries pumped into wells ranges from 35 to 50 per cent. A slurry having a water-to-cement ratio by weight of about 42 per cent (4.75 gal. of water per sack of cement) is probably a good average of the mixtures used. A sack of cement mixed with water in this ratio produces about 1.1 cu. ft. of slurry. As suggested above, this is a convenient average figure to use in computations to determine the number of sacks of cement necessary to fill a given space. Some operators prefer to use a more dilute mixture using 5½ gal. of water per sack of cement, producing a slurry weighing 15.5 lb. per gal. The graphs of Figs. 204, 205 and 206 are helpful in determining the quantities of cement and water necessary to produce slurries of different volumes, densities and water percentages.

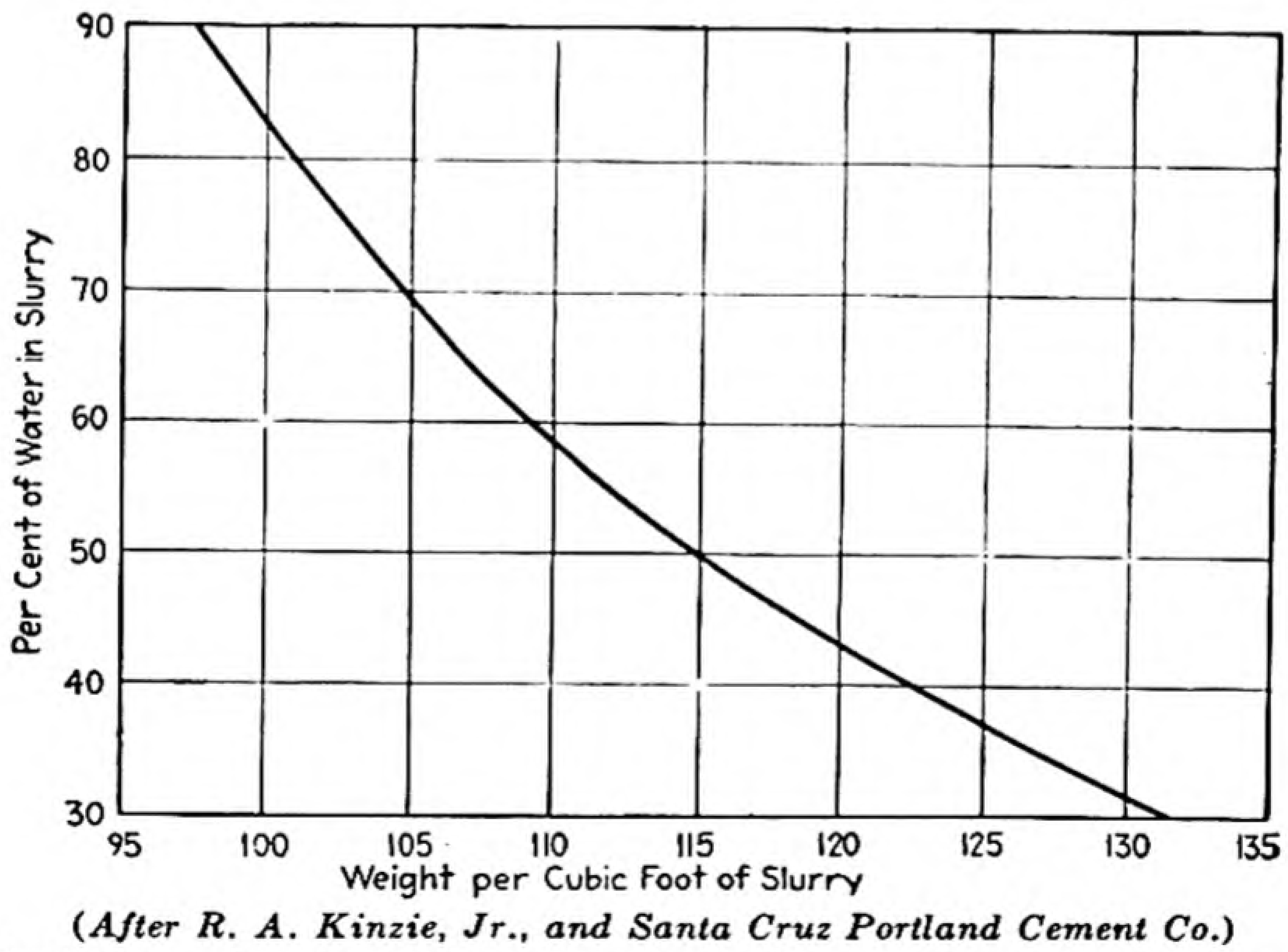
In planning a cementing operation, consideration should be given to pressure and temperature conditions to which the cement will be sub-

jected in the well before the slurry takes its initial set. Pressure conditions may be estimated approximately from the known depth to which the slurry must be pumped, the density of the well fluid (often about



(*After Doherty and Manning.*)

FIG. 204.—Amounts of water and cement necessary to form slurries of various percentages of water content.

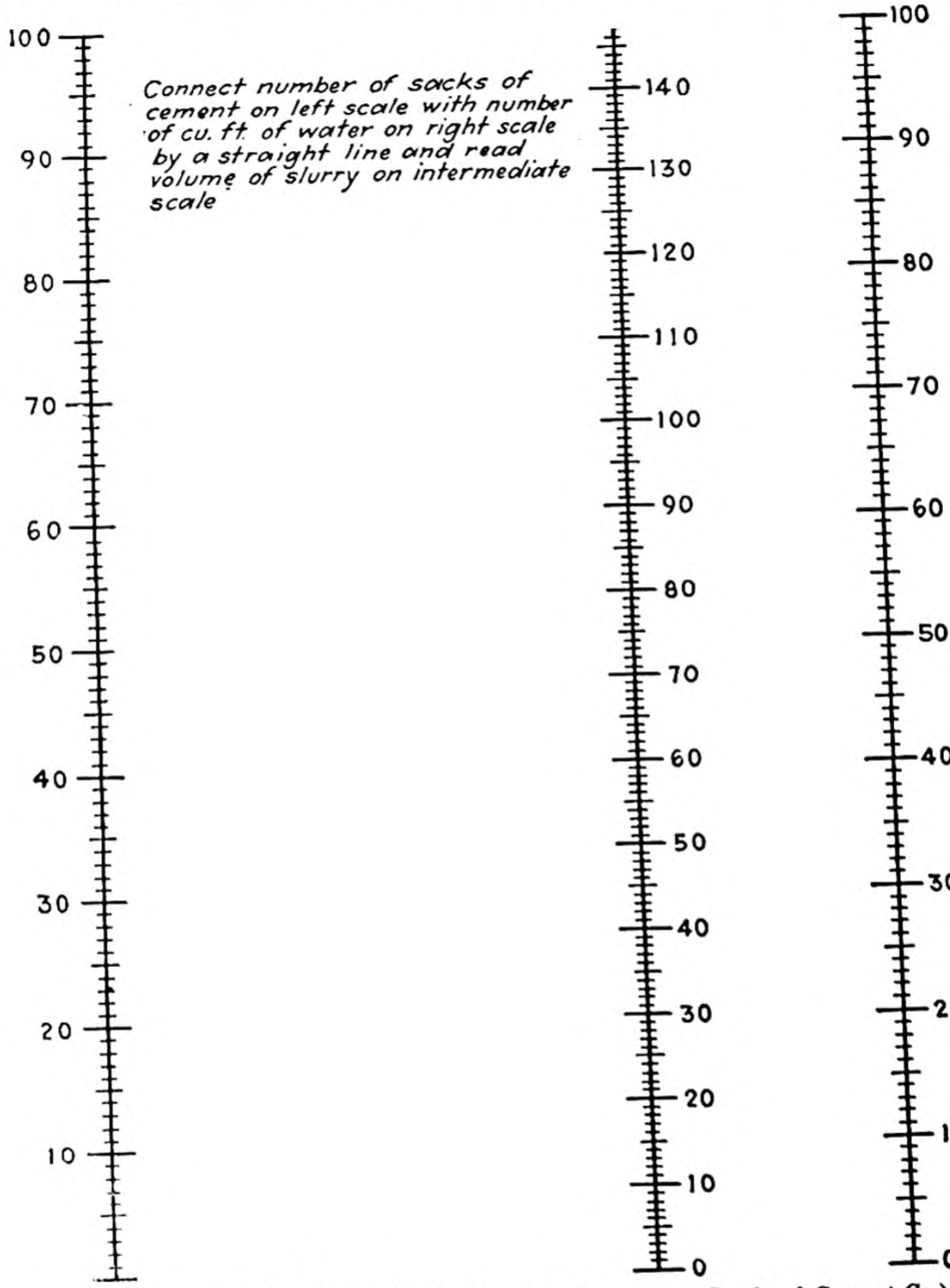


(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 205.—Variation of weight of neat cement slurry with percentage of water used.

50 lb. per 100 ft. of depth) and the probable pump pressure that will have to be superimposed on the static pressure of the well fluid to overcome well friction. The latter factor is influenced by many variables

and may not be estimated with accuracy, but often ranges from 150 to 200 lb. per 1,000 ft. of depth. Pump pressures used in squeeze cementing are often much greater—sometimes in excess of 3,000 lb. per sq. in. Obviously, when pressures of such magnitude are super-



(*After R. A. Kinzie, Jr., and Santa Cruz Portland Cement Co.*)

FIG. 206.—Alignment chart for estimating volume of cement slurry formed by different mixtures of water and cement.

imposed on the static pressure of the well fluid in cementing casing in a deep well, the cement will be subjected to pressures capable of materially changing its setting qualities and physical properties. If actual laboratory tests conducted with slurrified samples of the cement to be used are not possible at well pressures, an estimate of the influence of pressure

should be made on the basis of whatever data may be available (see page 496), and plans for the conduct of the cementing operation adjusted accordingly.

The maximum temperature to which the cement will be subjected prior to setting will be somewhat less than that indicated by the geothermal gradient. Circulation of fluid through the well will occasion a considerable reduction in bottom-hole temperature below the static equilibrium temperature, and the wall rocks, thus cooled, are only slowly heated by conduction from surrounding rock masses to their normal temperature. The cement temperature during placement should not exceed the normal bottom-hole circulating temperature. This can be estimated approximately with the aid of the following formula:

$$\text{Maximum slurry temperature} = \text{mud-ditch temperature} + \frac{\text{depth of well}}{\text{circulation thermal gradient}}$$

The circulation thermal gradient in some fields has a value of approximately 300 (1°F. for each 300 ft. of depth) and this figure may be used in calculating maximum slurry temperatures if specific information on the gradient in the well to be cemented is not available. Bottom-hole temperatures in deep wells often range above 150°F. and, as indicated in a previous section, important changes in the properties of some cements occur at such temperatures. The engineer will be guided by this knowledge in his plans for conduct of cementing operations if a high bottom-hole temperature is indicated. If necessary, a cement manufactured to meet slow-setting specifications will be selected to offset the accelerating effect of high temperature.

The condition of the walls of the well, clearance space around the casing and deflection of the well from the vertical will receive careful consideration in planning a cementing operation. The mud sheath on the wall of the well will be removed as far as possible by rapid circulation of low-density drilling fluid, preferably by direct impingement of hydraulic jets against the wall of the well, as provided by whirler shoes with downward directed baffles (see page 478). Accumulated clay on the wall of the well may also be removed effectively by action of an underreaming or wall-scraping tool or by the use of wire wall-cleaning guides (wall scratchers) attached at intervals to the outside of the casing. Lime-bearing muds are readily attacked by a 15 per cent inhibited hydrochloric acid, or treatment of accumulated mud on the walls of the well by chemical reagents is sometimes effective in disintegrating the clay sheath as a preliminary to a cementing operation. In any case, the object will be to remove all deposited clay and detrital material from the interval in which the cement is to be placed, so that the wall

of the well will present clean rock surfaces for contact with the cement. Only by substantially accomplishing this objective may a satisfactory bond between the wall of the well and the cement be achieved. Mud accumulations, left between the pipe and the wall of the well within the interval to be cemented, may remain occluded within the cement plug, forming "chimneys" that weaken it and perhaps affording opportunity for later passage of water through the plug.[11]

It is important that the casing be suspended centrally in the hole; otherwise it will occupy an eccentric position in the cement plug. Casing in a crooked hole is particularly apt to be eccentrically placed. Where the pipe rests against the wall of the well, it may be left without cement protection along the line of contact, perhaps leaving a channel through which water may later find its way. Reaming the well through the interval in which the cement is to be placed will reduce this hazard. Wall-cleaning guides, mentioned above, not only serve as a means of scraping the accumulated mud sheath from the wall of the well, but also assist in centering the pipe in the well. Use of the coaxial spiral (see page 479) on the outside of the casing through the interval to be cemented, and particularly about the lower end of a water string, will be effective in preventing channeling and in securing a proper distribution of cement around the pipe. It is the practice of some operators to raise and lower the casing in the well through an interval of several feet, as a means of securing better distribution of cement around the pipe, but this is scarcely feasible with very long casing strings.

If the interval to be cemented contains highly permeable strata, absorption of fluid from the well may result in formation of mud cakes of unusual thickness. Removal of these may permit the highly permeable beds to drain some of the water from the cement slurry when later it is placed in the well, thus forming a sheath of cement particles on the wall of the well and leaving the surrounding slurry of less than normal water content. Slurry drained of much of its water in this way sets rapidly—perhaps before the cement has risen to the point desired for the top of the plug. Thief sands that absorb water from the well fluid may be sealed before introducing the cement, leaving only a thin mud sheath on the wall of the well, by proper attention to mud conditioning. In more difficult situations, gel cement or fiber cement may be used to restrict fluid loss to highly permeable strata; or the walls may be given a quick wash with hydraulic lime to seal the pores of the offending strata, just before introducing the cement.

The cement slurry is not likely to be contaminated or diluted with saline ground water or be subjected to admixture with oil or agitation by flowing gas, if all formations yielding such fluids have been properly mudded in the process of drilling. However, subsequent removal of

the mud sheath from the walls of the well prior to cementing may admit high-pressure fluids. If there is evidence of this, the walls may again be mudded under pressure until flow from the formation ceases, after which treatment with hydraulic lime may consolidate the clay sheath prior to introduction of the cement. Or squeeze cementing may be resorted to as a means of developing pressure conditions in the well in excess of the pressure existing in the formation, thus driving cement into the permeable beds until they are sealed.

The engineer in charge of a well-cementing operation must give careful attention to the surface equipment and facilities to be employed, in order to be assured that they are capable of performing their assigned tasks and of meeting the requirements imposed. Will the mixing facilities be able to mix the cement and water rapidly enough and always with proper amounts of each to assure necessary uniformity in the slurry? Will a sufficient supply of water be available and is it of suitable purity? Are the water-gauging facilities dependable? Are the pumps to be used of sufficient capacity and are they capable of developing sufficient pressure to force the necessary volume of slurry into place in the well within the thickening time of the cement? Is the power source adequate and dependable? Are the well-head and pump connections capable of withstanding the pump pressure likely to be imposed? These and other details are important inasmuch as any adverse condition may prevent successful completion of the cementing operation. The work must proceed with precision and the timing of each phase of it must be carefully planned. All conditions must be such as will ensure a continuous operation of the equipment with a minimum of interruption in flow of slurry into the well due to handling of cement or mechanical failure of the equipment.[17]

CEMENTING PROCEDURES

There are many different types of cementing operations and methods of conducting them. Space permits of description of but a few of the more common ones.

Cementing a Water String by the Two-plug Method.—In an earlier section, the method of pumping cement through casing between two moving plugs (the Perkins process) was described in general terms. The following paragraphs describe the procedure appropriately followed in cementing a water string by this method, one of the more common types of cementing operations. It is assumed that equipment of the Perkins or Halliburton type, described on page 486, will be used.

In cementing a water string, consideration should be given to the selection of the formation in which the pipe is to be "landed"—that is, the horizon in which the casing shoe is to be set. Well-consolidated shales of low porosity and permeability, or hard, well-cemented sandstones are satisfactory for this purpose. Beds of limestone or marl are also suitable if impermeable to passage of water. If the formation in which the casing is cemented is sufficiently permeable and the cement plug does not extend through its full thickness, it may be possible for top water to flow around the cement plug through the surrounding formation, and down

into the lower part of the well. Ten feet of dense, impermeable shale is sufficient in which to effect a top-water shutoff, but a greater thickness is desirable. Cores afford the best evidence of the type of formation to be selected and when, in the course of drilling, the horizon is approached in which a water string is to be set, the formation may be cored continuously until a suitable stratum is found in which to "land" the pipe. If possible, 10 or 15 ft. of the impermeable formation should be left below the bottom of the cement plug in which to drill a pocket useful in making a water-shutoff test. In cementing a long string of heavy casing, it is usually difficult to be certain that the casing shoe is at exactly the depth chosen. Often the casing will be suspended with the shoe 20 ft. or more off bottom. Where high-head top waters are not in evidence, the well may be drilled to completion depth before cementing the water string. In this case a "bridge" must be formed in the well at the point where the shoe of the water string is to be set, to confine the cement and prevent if from finding access to the lower part of the well.

Before running casing into the well, the hole should be reamed with a drilling bit of proper size—often a four-way reamer—to assure free passage for the casing. Cable-drilled wells are often enlarged by under-reaming for 100 ft. or more above bottom to provide additional space between the wall of the well and the casing in which cement may accumulate and thus ensure a thicker cement sheath about the pipe. Rotary-drilled wells may be wall-scraped through the interval in which the cement is to be placed, or at least 100 ft. above bottom, to remove the mud sheath on the walls of the well and expose clean rock surfaces for contact with the cement. In lieu of this, wire wall-scraping guides may be placed at intervals along the casing near the lower end, and the pipe manipulated in such a way as to scrape off the mud sheath.

The casing is equipped with one or another of the several styles of cementing shoes or baffle collars (see page 477) and suspended from a casing spider in the rig cellar or on the derrick sills, with the shoe 10 or 20 ft. off bottom. Circulation of drilling fluid is then established, down through the casing and back to the surface through the annular space between the casing and the wall of the well. Circulation is maintained until all drill cuttings, sand and detrital material are removed from the well and the fluid has been brought to uniform consistency throughout. The density and viscosity of the fluid should be as low as may be consistent with safety, in order to permit the cement slurry to displace the drilling fluid upward through the annular space with minimum pump pressure. Apparently in some cases, free circulation is established, but the flow is through "chimneys" on only one side of the pipe, or through channels about it. Considerable mud may thus remain lodged about the lower end of the casing and, when the cement is introduced, it rises through the channels already established by circulation, and an irregular plug consisting partly of cement and partly of mud will be the result. This can best be avoided by continuing circulation at high velocity aided, if possible, by occasional raising and lowering and rotation of the casing, until the accumulated mud and detrital material is disintegrated and removed.

With the necessary quantity of cement at hand, either in bags or in tank trucks equipped for bulk delivery; with an ample supply of water suitable for mixing slurry; with the pumping equipment, cementing plugs, gauging tanks, cementing-head and well-head connections all in readiness and in working order, preparations are made for mixing the slurry promptly and pumping it down the casing. For this work, most operators utilize the facilities of a service organization which brings to the well all specialized equipment not ordinarily used in routine drilling operations. The service organization also sends its own technical personnel to assume practical charge of the work, but the owner of the well is generally required to furnish the necessary number of men to do the physical work of opening and dumping cement bags and

manipulating the surface equipment. A fee of \$250 per job is generally charged by the service organization.

The arrangements and connections at the casing head are important in permitting rapid introduction of the cement plugs and quick changes from one type of fluid to another. The hookup should be so arranged that the pump suction lines may draw upon a supply of cement slurry, drilling fluid or water as required, merely by adjusting valves in a pipe manifold. Arrangements should also be made that will enable the operator quickly to connect the cement pumps either in series or in parallel or to operate them independently, or to change the well-head connections from the cement pumps to the rig slush pumps. A quickly adjusted type of cementing head, such as that described on page 481, is convenient in inserting the cementing plugs in the casing with minimum loss of time. The upper plug may conveniently be supported in a steel capsule above and connecting through the cementing head. In this case, the Halliburton measuring line, described on page 482, is often used.

After circulation is assured and all is in readiness, from 10 to 20 bbl. of water may first be pumped down the casing to wash adherent clay from the inner walls of the pipe. The cementing head is then disengaged, the lower plug is inserted in the casing and the head again placed in operating position. Mixing of cement slurry begins, the low-pressure cement pump is started and slurry flows down the casing, forcing the lower of the two cementing plugs ahead of it. The lower plug eventually comes to rest in the cement shoe or baffle collar at the lower end of the casing but, owing to the design and construction of the plug, the cement passes through it and out into the well through the lower end of the casing.

As cement slurry is pumped into the casing, being of greater density than the fluid with which the well is filled, it tends to sink and displace the latter, so that very little pump pressure is at first necessary. This density advantage, however, gradually diminishes as the work proceeds and the cement emerges from the lower end of the casing, until equilibrium is established and the pump pressure must then gradually be increased. Pressures of many hundreds of pounds per square inch are sometimes reached in deep wells before the cement is entirely displaced from the casing.

When the last of the cement has entered the casing, the upper of the two cementing plugs is released from its capsule so that it enters the upper end of the casing; or, if no capsule is used, the cementing head is disengaged and the plug inserted in the casing. Pump connections are again established at the casing head, and the pump suction line changed so that about 10 bbl. of water is forced down the casing after the upper plug. This is done to remove the adherent coating of cement on the inner wall of the casing. Drilling fluid is then pumped into the casing and the cementing plug forced down as rapidly as possible. If rotary drilling equipment has been used in drilling the well, the rig slush pumps may be used for this purpose. A high-density mud fluid is preferably used to pump down the upper plug, in order that its high hydrostatic pressure may help to offset the high density of the column of cement slurry about the casing and assist the pumps in overcoming the well friction.

When the two cementing plugs come together in the casing shoe or on the baffle plate near the lower end of the casing (if one is used), there will be a sudden increase in pump pressure, stalling the pumps and indicating satisfactory completion of the work. Although, if all goes well, the operator may depend upon the action of the plugs and pump to indicate when all cement has passed out of the casing, it is well to have some means of checking the progress of operations that may be relied upon to indicate the position of the upper plug in the event that something goes wrong. Possible accidents that may prevent orderly completion of the work include caving of the walls of the well, cutting off circulation, splitting or parting of the casing, "hang-

ing-up" of the plugs as a result of some obstruction in the casing, or failure of the washers on the upper plug to hold against the pump pressure. As a precaution, it is customary to calculate the volume of the casing and, when an equal volume of fluid has been pumped down after the upper plug, displacement of all of the cement slurry from the casing is indicated. The fluid so used may be gauged carefully in measuring tanks or metered; or a rough computation of the fluid volume may be based upon the displacement of the pump plunger per stroke and the number of strokes. Downward progress of the upper cementing plug may be positively indicated by use of the Halliburton depth-measuring device described on page 482.

There has been considerable discussion concerning whether or not air finds its way into the cement about the casing shoe when the two-plug system is used. Owing to the greater density of the cement slurry in comparison with that of the well fluid, it often continues moving down the casing when the cementing head is opened to admit the upper plug so that, when the latter is inserted, a body of air is trapped above the cement. As this air is pumped down the casing, it will eventually be forced through the lower plug and out into the well. Though greatly compressed by the hydrostatic pressure to which it is subjected, it is a potential source of voids in the cement at the critical point about the casing shoe. A plug capsule for the upper plug, described above, prevents admission of air to the casing and is used by some operators, primarily for this reason. Another method of avoiding air pockets in the lower part of the cement plug is to leave some of the cement in the casing. This may be done by placing a perforated baffle plate in the casing one or two joints above the casing shoe, thus stopping the cementing plugs at this point. Another method allows the lower plug to proceed to the valve in the casing float shoe but uses a spacer in the form of a 4- by 4-in. timber about 20 ft. long between the two plugs. Or the Halliburton measuring line permits of stopping the upper plug at any desired point. By either of these methods, the latter part of the cement, which is likely to contain air, is retained within the casing, later to be drilled out with the tools. Another reason for leaving some of the cement in the casing is found in the tendency of the cement particles to settle, thus leaving the upper part of the column of cement slurry within the casing very dilute, consisting, perhaps, chiefly of water. Sometimes too, the upper part of the cement column becomes diluted with wash water or drilling fluid, owing to leakage past the upper plug. Cores taken of the cement left inside the casing, after cement jobs are completed, have shown that the cement often lacks strength and hardness. Usually operations are planned to leave at least 25 ft. of cement in the casing. Some operators recommend 10 ft. for each 1,000 ft. of depth.

In placing large amounts of cement in deep wells by the two-plug process, it is important that the cement slurry be mixed rapidly and forced down the casing with minimum loss of time; also, that the rate of mixing of the slurry be maintained substantially constant. During the mixing of the cement, a gallon sample of the slurry may be frequently weighed and the amount of water used regulated to such extent as may be necessary to keep the density uniform. If the slurry is continually agitated and moved so rapidly down the casing that it is at all times in turbulent flow, it will not show serious stiffening tendencies during the time normally necessary for placement. However, if delays occur and the routine of mixing and pumping is interrupted, the slurry will begin to stiffen and will move down the casing as plastic "slugs." On passing out of the casing, this highly viscous slurry may become contaminated with mud and fail to fill recesses in the wall of the well as effectively as if the slurry were in a truly liquid condition. This result is especially likely to occur if high temperatures prevail. The period of agitation and rapid flow of the slurry should not extend beyond the time for the initial set; otherwise its setting properties and ultimate strength will be seriously impaired.

After all cement is in place in the annular space, a valve is closed at the casing head, confining the fluid in the casing and maintaining pressure within it. Use of a back-pressure valve in the cement shoe, as pictured in Fig. 158, eliminates this necessity. Cement pumps, mixing equipment and well-head connections may then be removed. If the column of casing is a short one, it may be lowered until the shoe rests on bottom, but danger of column failure and deflection of the pipe due to its own weight will normally require that it be suspended with the shoe off bottom until the cement has set and hardened. Even then, much of the weight of the pipe may have to be supported from the surface. Cement left in the lower end of the casing, in and around the cement plugs and the cement shoe and in the hole below the shoe, is not drilled out until the cement has taken its final set and has attained sufficient strength to resist cracking and displacement by the drilling tools. This normally requires at least 48 hr., and this period of waiting is specified by regulatory authorities in some states.

Cementing through Perforations.—In some situations, it becomes necessary to place cement in a certain interval behind a column of casing, without cementing other portions of the annular space above or below the cemented interval. To accomplish this, perforations are provided in the casing through which the cement is passed and the casing is bridged below the perforations. Cement slurry is then forced down to a point opposite the perforations through a column of tubing inside the casing, with a bottom packer set against the casing. Two cement retainers may conveniently be used for this purpose, first setting one to serve as a bridge just below the perforations, then removing the tubing and running in again with a second retainer to confine the cement slurry within the casing to the perforated interval. If it is known before the casing is placed in the well that a particular interval is to be cemented by this method, round holes may be bored in the pipe to come at the proper depth in the casing column, before it is lowered into the well and a "basket" placed on the outside of the casing below the lowermost perforation, to prevent the cement from moving down the annular space about the pipe. If it is not known in advance that a "C.P. job" (cementing through perforations) is to be performed, the casing may be gun-perforated in the well at the desired depth. The following typical operations will serve to illustrate situations in which cement may conveniently be placed by this method.[24]

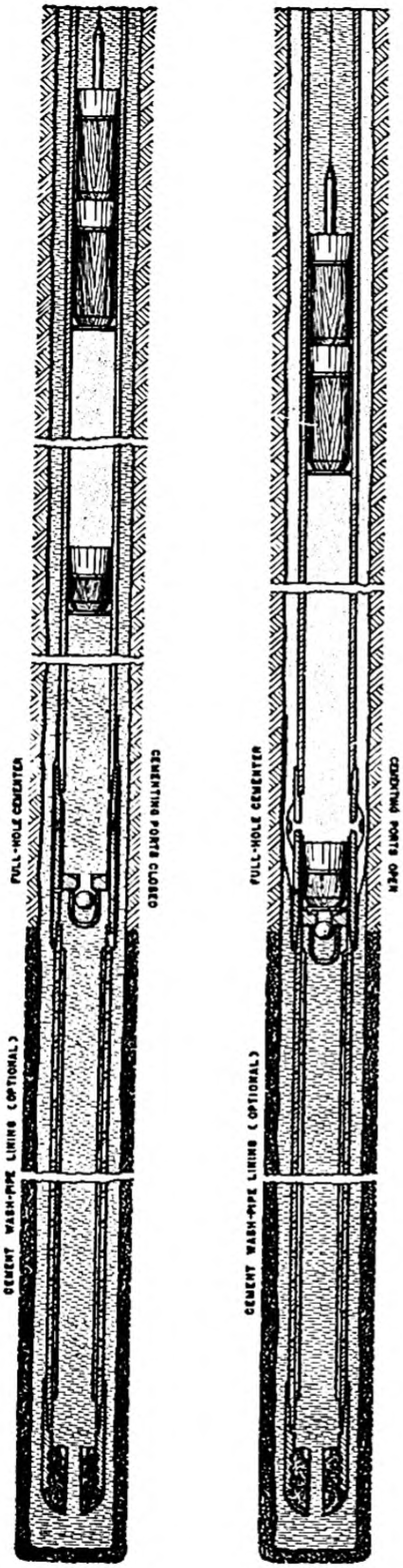
1. Cementing a Combination String.—In order to conserve working space in the bottom of a well, it may be decided to make a top-water shutoff and carry the same column of casing through the underlying oil sand. When used in this way, the single column of casing, serving both as a water string and an oil string, is called a "combination string." The cement used to shut off top water is conveniently placed by forcing it under pump pressure through perforations in the pipe. If it is known that this is to be done, a perforated joint is placed in the column at the proper point as it is being lowered into the well, with a basket around the pipe below the lowermost perforations. A bridging plug in the casing at this same depth prevents cement from passing below this point. A cement retainer is then lowered into the casing on the lower end of a column of tubing and circulation established through the retainer and casing perforations and back to the surface between the casing and the wall of the well. Cement slurry in calculated amount, sufficient to form a cement plug of suitable length, is then pumped down through the tubing and retainer and out through the perforations into the annular space. Careful account is kept of the amount of water or drilling fluid pumped down through the tubing after the cement and, when it is estimated that nearly all of the cement is out of the tubing, the circulation joint just above the retainer is broken and the small residue of cement left in the tubing is circulated back to the surface through the annular space between the tubing and the

casing. The tubing and the circulation joint are then removed from the well, leaving the retainer with its back-pressure valve closed, locked in the casing just above the perforations. After the cement has set and hardened, the retainer and short column of cement between it and the bridging plug within the casing are drilled out. If screen pipe has not been provided opposite the oil-producing formation, the oil string may then be gun-perforated in this interval.

2. Multizone Completion Involving Cementing a Perforated Liner in Two or More Intervals.—In some fields, production is had from several productive zones, separated from each other by intervals of shale, perhaps containing some water that must be excluded. The oil string is assembled at the surface, with shop perforations provided at the appropriate depths, and baskets mounted at suitable points to confine the cement to the desired intervals. When the oil string is in position and the well fluid is properly conditioned, with a plug set in the pipe below the lowermost perforations, a cement retainer is lowered on a column of tubing and lodged in the casing just above the lower series of perforations. Cement is pumped through the tubing and retainer, out through the lower series of perforations above the lowermost basket, rising behind the casing and flowing back into the casing through perforations just below the next higher, inverted basket. Excess cement flowing back into the casing is circulated back to the surface through the annular space between the tubing and the casing, by disengaging the tubing from the retainer at the circulation joint and circulating water or drilling fluid down through the tubing. The tubing is then withdrawn, a second retainer lowered and set in the casing to serve as a bridge just below the next higher series of perforations, and the entire process repeated to cement the interval between the two oil sands. In the same fashion, the interval above the uppermost oil sand is cemented. After the cementing operations are completed, the retainers, bridges and short sections of cement within the casing are drilled out and the blank pipe opposite the oil sands is then gun-perforated to admit oil and gas.

Some operators are content to cement all of the annular space behind a liner extending through the oil sands as well as through the intermediate shale bodies, then gun-perforating both the pipe and the cement sheath opposite the oil sands. Although perforations made with the gun perforator are quite capable of penetrating the cement plug as well as the steel liner, it is believed that this practice is likely to restrict oil production somewhat and that a method which leaves the oil-producing intervals free of cement—such as that described above—would be preferable.[33]

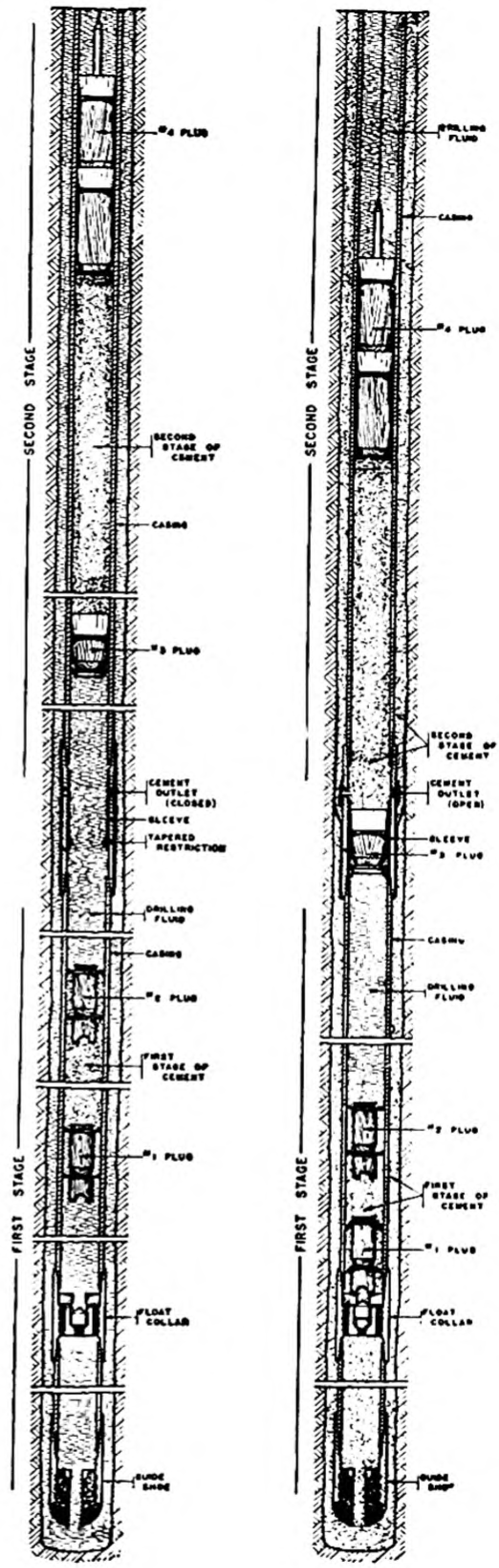
Full-hole Cementing.—The Halliburton Oil Well Cementing Co. has developed a device to facilitate cementing a combination string in a well, which permits of carrying the same size of casing through the producing formation as is used to exclude top water, thus conserving working diameter in the lower part of the well. The larger diameter screen pipe, thus made possible, permits of greater production efficiency. The full-hole cementing device consists of a short perforated collar containing a back-pressure valve and a sliding sleeve which closes the cement ports as the column of pipe is lowered into the well. The screen pipe suspended below the collar is equipped with a cement "wash-pipe" lining, also developed by the Halliburton Co. With the combination string made up, as shown in Fig. 207, and in place in the well, fluid is circulated down through the full length of the combination string and back to the surface through the annular space about the casing, thus removing all detrital material from the annular space about the casing. When this has been accomplished, the cement is pumped down the casing between two moving plugs in the conventional manner. The lower plug opens the cement ports by moving the sliding sleeve downward and comes to rest on the seat of the back-pressure valve, thus preventing the cement from moving down into the screen pipe below. A basket about the cement ports is also expanded against the wall of the well when the sliding sleeve is depressed.



A B

(Courtesy of Halliburton Oil Well Cementing Co.)

FIG. 207.—Operation of "full-hole" cementing process. *A*, plugs and cement moving down casing; discharge ports closed. *B*, lower plug at limit of travel; discharge ports open.



A B

(Courtesy of Halliburton Oil Well Cementing Co.)

FIG. 208.—Operation of multiple-stage cementing process. *A*, cementing plugs with two stages of cement moving down casing. *B*, lower plug at lower limit of travel, cement being displaced from casing.

Cement flows out through the ports into the annular space until the upper plug, moving down the casing after the cement, comes to rest on the lower plug and again closes the cement ports. When the cement has set, the plugs and back-pressure device are drilled out, the cement lining inside the perforated pipe is reamed out with a diamond-pointed bit, and the well is ready to produce.

Multiple-stage Cementing.—The Halliburton Oil Well Cementing Co. has also perfected a system for discharging cement through perforations in a column of casing at two or more elevations in one operation, thus removing the necessity for forcing all of the cement down through the full length of the column. The time necessary for placement of the cement and the pump pressure necessary are thereby reduced. By this means, it is also possible to place cement outside of the casing in certain formation intervals, leaving intermediate intervals free of cement. The "multiple-stage device" which makes this possible is a perforated collar coupled into the column of casing wherever cement is to be discharged. The cement ports in this device are normally closed by a sliding collar, utilizing the same principle as the full-hole cementing device illustrated in Fig. 207. However, the multiple-stage device has no back-pressure valve. The sliding sleeve is forced downward, opening the cement ports, by the lower cement plug preceding the cement down the casing. This plug ultimately comes to rest in a tapered constriction just below the cement ports. Figure 208 illustrates the arrangement of cement plugs and the multiple-stage device for a situation in which the cement is to be placed in two stages, one portion passing down under the shoe of the casing and up behind the pipe in the conventional way, the other part to be "spotted" some hundreds of feet higher, by being forced through perforations at this level. Figure 208*A* shows two stages of cement slurry moving downward through the casing. Owing to special design of the two lower plugs, the lower stage passes through the multiple-stage device without opening the cementing ports. Figure 208*B* shows the first stage of the cement in place behind the lower part of the casing. Plug 3, just ahead of the second stage of the cement, has reached the device and has forced the sliding sleeve downward, uncovering the cementing ports and allowing the cement slurry to pass out into the space behind the casing and above the device.

Squeeze Cementing.—Under conditions frequently presented in attempting to exclude water or gas from wells, it is advantageous to confine cement slurry within tubing or other appliances so that it has access to only a certain part of the well, and then to apply hydrostatic pump pressure with the purpose of driving the fluid into the wall rocks before the initial set occurs. By this means, the pore spaces, crevices, joint planes and other rock openings may be effectively sealed, forming an impermeable sheath of cemented rock of considerable thickness about the wall of the well. Greater security against passage of fluid around the cement plug is thus afforded.

Preliminary operations usually consist of thorough cleaning of the mud sheath from the wall of the well by washing and perhaps, by "scratching" or scraping to expose fresh wall surfaces to the cement slurry. An effort is made to enlarge the well to a diameter that will result in removal of formation sealed by gelled clay, forced into the wall rocks during the drilling operation. As explained on page 284, the clay sheath is usually deposited directly upon the surface of the wall of the well and ordinarily does not penetrate the wall rocks more than a small fraction of an inch. Before attempting to force cement into the wall rocks, water is forced into the formation under high pressure with the purpose of breaking down the formation resistance, so that the cement slurry may later enter more freely. Pressures ranging as high as 3,000 to 4,000 lb. per sq. in. or from 50 to 100 per cent in excess of the normal hydrostatic bottom-hole pressure are used in breaking formation resistance. Hydrochloric acid is used instead of water in limestone formations. When the necessary pressure is reached and water begins to flow from the well into the formation in quantity, the

pressure necessary to maintain a certain rate of flow will gradually diminish but finally approaches a constant minimum value. When this condition of approximate equilibrium is attained, the formation is ready to receive the cement. The effect is probably to enlarge the drainage channels and perhaps force strata apart along bedding planes, thus increasing formation permeability.

When cement slurry is confined in place in the section of the well to be cemented, pump pressure is applied sufficient to force fluid from the well into the formation. Filtering through the more permeable strata, the slurry tends to form a filter cake at and near the wall of the well. Some of the surplus water is squeezed out into the formation and the residue of thickened slurry quickly takes its initial set. The pressure applied is preferably about 3,000 lb. per sq. in., but is limited by the capacity of the pump or the collapsing strength of the casing. Excessive pressure must be avoided as resulting rapid flow of cement into the formation may prevent it from setting properly. To facilitate flow into the formation, a thin slurry containing about 10 gal. of water per sack of cement and weighing about 15 lb. per gal is employed. If both oil- and water-bearing strata are exposed to the cement, most of it will enter the water-bearing strata and the cement formed at the face of the oil-bearing strata will be soft and easily disintegrated by wall scraping.

Many different variations of the squeeze cementing process have been devised, but the following descriptions are typical:[24]

1. Recementing a Defective Shutoff.—A problem frequently presented is that of recementing a water string following a conventional shutoff that has been only partly successful. Cement placed around the casing above the shoe has perhaps channeled, or for some reason does not prevent water from finding its way around the shoe into the hole below. In such a situation, a column of tubing 2 or 3 in. in diameter, with a cement retainer and circulation joint on its lower end, is lowered into the casing until the packer of the retainer is only a few feet above the casing shoe. The retainer is tripped so that the packer and slips are set against the inside surface of the casing, thus locking the retainer in position so that it cannot be moved either up or down. Circulation is established through the circulation joint, back to the surface between the casing and the tubing. The valve in the circulation joint is then closed and from 10 to 50 bbl. of water forced through the retainer into the formation. Thin cement slurry is then forced down the tubing and through the retainer into the well cavity below the casing shoe. A final pressure of about 3,000 lb. is applied, thus driving the fluid slurry into all crevices and to some extent, into the formation surrounding the casing shoe. From 50 to 100 sacks of cement may be used, and the slurry equivalent of 10 sacks or more may be squeezed into the formation. After the desired pressure has been reached, any excess cement remaining in the tubing is flushed out by opening the circulation joint and flushing out the tubing and annular space with water or drilling fluid. The retainer back-pressure valve remains closed, thus maintaining pressure on the cement. The tubing and circulation joint are then disengaged from the retainer and withdrawn from the well, leaving the retainer lodged in the casing to be drilled up with the tools after the cement has set and hardened.

2. Multiple-batch Cementing.—In very permeable formations, the cement drains away so rapidly that it is impossible to maintain pressure while the cement is setting. In this event, cement slurry may be injected in several stages, using from 35 to 100 sacks in each batch. The procedure outlined in the foregoing paragraphs is followed except that after all of one batch of cement has entered the tubing, water is pumped down through the tubing and retainer in sufficient quantity to free them and the well cavity below of residual cement. After the cement has stood for about 3 hr. and has taken its initial set, the entire process is repeated with a second batch of cement. By opening the circulation joint above the retainer, excess water in the tubing is dis-

charged into the space between the tubing and the casing as the second batch of cement is forced down the tubing. The circulation joint, of course, is closed just before the cement reaches the retainer. Additional batches may follow until the formation will no longer absorb cement slurry undei high pressure. Some operators do not wait for the cement to set between injections, using alternating slugs of cement and water in a continuous operation.[13]

TESTING EFFICACY OF WATER SHUTOFFS

On completion of a cementing job or other work designed to exclude water from a well, a test should be made to determine whether or not it has been successful. If cement has been used, such a test should not be made until it has had time to set and harden properly. Any cement left within the casing is first drilled out, and a hole drilled for a depth of 10 or 20 ft. below the shoe of the water string. The fluid is then bailed from within the casing until the level is sufficiently below that at which the fluid stands outside the casing, to allow water to enter if it is able to do so. After bailing, the fluid level within the casing is carefully measured and recorded. The well is allowed to stand 12 hr. or more, when a second measurement of the fluid level within the casing is made. If the level has not changed materially, the shutoff is regarded as successful. Draining of films of water down the inner walls of the casing after bailing may raise the fluid level slightly. Even though a slight leakage of water under the shoe is apparent, it may be considered too slight to justify further repair work.

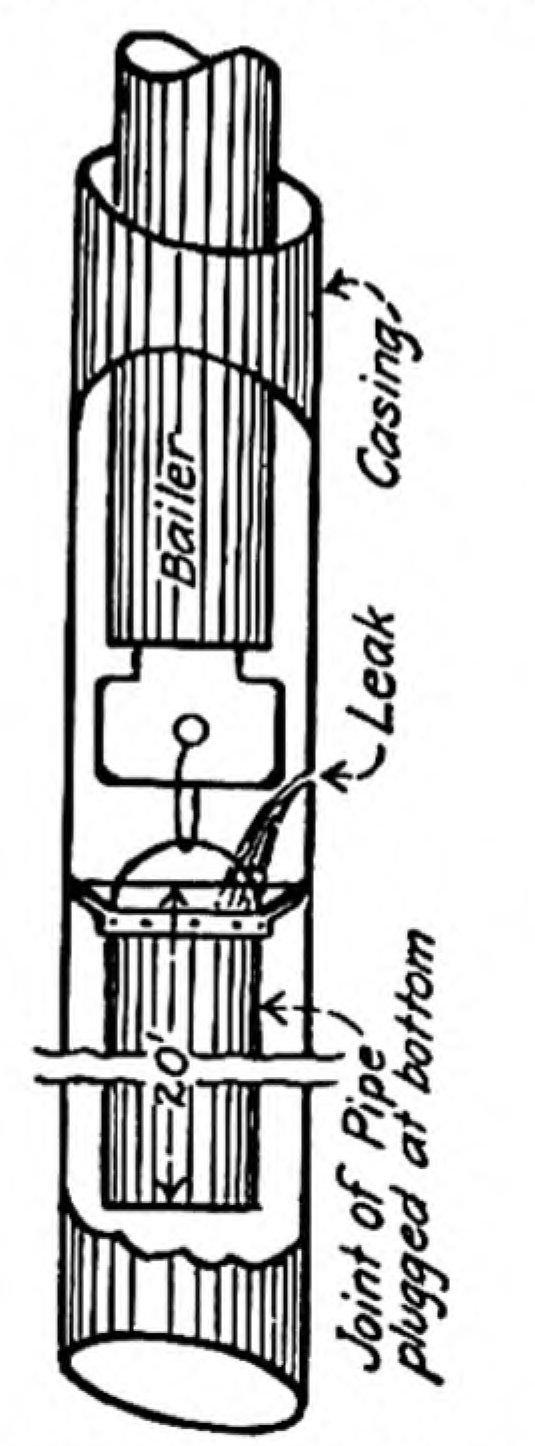
Occasionally gas entering the casing from the formation below the shoe of the water string will cause the fluid within to rise, perhaps leading to the erroneous conclusion that water has not been effectively excluded. In some fields, such as the Ventura field of California, owing to the presence of large quantities of gas in the formation, it is considered unsafe to lower the fluid level inside the casing sufficiently to secure a fair test of water shutoff by the usual method. In this case the fluid level within the casing is lowered only about 500 to 700 ft. below the surface and samples are then taken of the fluid in the bottom of the well. The overlying formations are highly saline and any increase in the percentage of salt in the well fluid is considered evidence of an unsuccessful shutoff.

Measurement of fluid level within a casing may be made with the aid of a heavy plumb bob and a steel measuring line, on a suitable reel mounted above the well mouth on the derrick floor (see page 477). If cable drilling tools are available, it is customary to make fluid-level measurements with the sand line and bailer. The bailer is run into the well until it is submerged or partly submerged below the water level. A mark is then made on the sand-line level with the derrick floor and, as the bailer is withdrawn from the well, the length of line is measured below this mark to the point where first moisture on the line or bailer shows the

water level to have been. The process of measuring the sand line is readily accomplished by determining the length of line from the derrick floor up over the crown block and down to the level of the sand-reel flanges. This unit of measurement is applied by tying a strand of manila fiber to the line at the level of the derrick floor and raising the bailer until this strand reaches the sand-reel flange. The strand is then removed and another placed on the sand-line level with the derrick floor, and the process is repeated until the wet portion of the cable or bailer emerges. The number of strands untied from the line at the sand reel, plus one, multiplied by the unit length over the crown, plus the fractional interval from the last strand down to the derrick floor (as measured with the gauge stick or tape), is the depth to water level.

REPAIRING UNSUCCESSFUL SHUTOFFS

If tests made as outlined above indicate that the effort to exclude water has not been successful, further tests must be made to determine the nature of the difficulty. Perhaps, owing to one or another of the physical and chemical variables already discussed, the cement has not set; or, if it has set, open channels through it may have been left. Perhaps the cement plug is structurally misplaced and the water is coming from formations below the plug. Occasionally, casing leaks above the shutoff will admit large quantities of water.



(*After R. E. Collom, California State Mining Bureau, Department of Oil and Gas.*)

Fig. 209.—Method of using casing tester.

Locating the Source of Water Entering a Well.—In locating the source of water entering a well, tests should first be made to determine whether or not the casing leaks. Testing for casing leaks may be conveniently conducted with a casing tester (see Fig. 209), which is alternately lowered to successively greater depths and hoisted to the surface until it brings up water. The casing may have become worn through by abrasive action of the drilling cable or drill pipe; or it may have split at a defective weld, or as a result of application of a swage; or the leak may be at a loose collar which is cross-threaded, or which has become unscrewed in the well.

If the leak is not in the casing, a test should next be made to determine whether water is finding its way down through or around the cement plug and under the casing shoe, or whether it comes from some lower source. For this purpose, a "bridge" should be placed a few feet below the shoe, sealing off the hole that has been drilled below. This plug is built up from bottom in successive stages with the aid of wooden or lead plugs and cement. If further tests indicate that water has been excluded by this process, it may be concluded that the shutoff has been placed too high and water-bearing formations occur below the casing shoe.

We may locate the source of water in a well below the shoe of a water string by plugging with cement in stages, testing after each stage to determine whether or not

water has been excluded. An alternative plan is that of plugging back to the shoe of the water string and then drilling out in stages.

In drilling it is a good plan to obtain and preserve samples of the fluid from each water-bearing horizon penetrated. Chemical analysis may disclose characteristic changes in saline content in the waters from different horizons. Later, if water exclusion operations are unsuccessful, it may be possible to identify the water entering the well and determine the horizon from which it comes by making a chemical analysis and comparing the result with the record of earlier analyses of samples taken during the drilling period.

If samples are not taken during the drilling stage and analyses made, we may still make use of chemical analysis as a means of identifying the source of water by filling the well with fresh water or mud fluid, then bailing or swabbing out enough fluid to cause water to enter from the formation, sampling at various depths and making chemical analyses in the hope of finding a variation in saline content of the well fluid. An increase in saline content will necessarily be opposite the point at which water enters.

Use of one or another of the several water-locating devices described in an earlier section (pages 457–458) affords the most certain and accurate means of determining the point at which water is entering a well following an unsuccessful water shutoff. With the Water Witch, the Lo-kate-it device, the Dale photoelectric cell or resistivity instruments used in making electrical logs, the point of admission of water may be determined quickly and precisely. The information thus secured provides a dependable basis for planning remedial measures.

Remedial Measures.—The nature of the repair operations that must be undertaken, in the event that an attempted shutoff has proved unsuccessful, will depend upon the source of the water and the way in which it finds admission to the inner portion of the casing. If cement has been used and has failed to set, it will perhaps be possible to raise the casing, bail out the cement slurry and repeat the cementing operation after studying the cause of the failure and making such changes in methods or materials as seem desirable. If the cement has set properly but has been ineffective, a more difficult problem is presented. If tests indicate that water is entering under the shoe of the water string, a squeeze job, using auxiliary tubing and a bottom packer or cement retainer, affords a convenient and promising method of recementing (see page 524). If this fails, the casing may be parted above the cement plug, the upper part of the casing withdrawn and the lower part sidetracked by redrilling the lower part of the hole and deflecting it to one side of the original hole. Another plan is that of drilling deeper and cementing a smaller water string inside of the defective one. This, however, is costly and involves sacrifice of working area in the well.

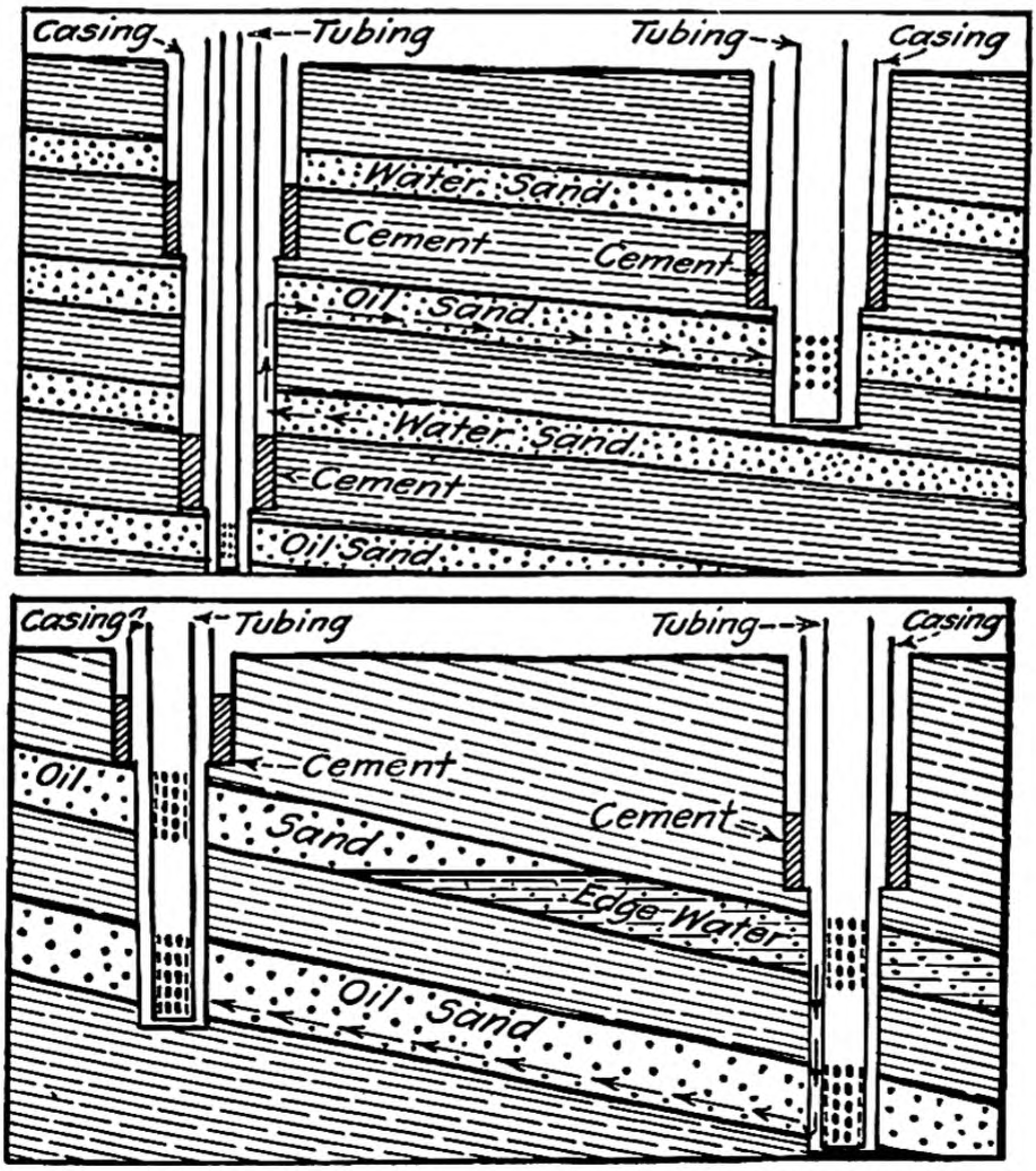
If water is entering through a leak in the pipe above the point of water shutoff and the head likely to be developed above the leak is not great, drilling may be continued and the well completed, allowing the inner string of casing, or "oil string," to extend to a point above the leak in the water string and setting mechanical packers between the two casings to exclude the water. If this procedure is considered unsafe, owing to the hydrostatic head likely to be developed, a bridging plug may be set in the casing below the point of water admission and an effort made to close the opening in the casing with cement. For this operation, a C.P. job is performed, similar to that described above in connection with the cementing of a combination string (see page 521). If the hole in the casing is too small to permit of free passage of cement slurry, it may be gun-perforated at the same depth or slightly below and cement pumped through the holes thus formed. If impossible to gain circulation through the perforations and outside the pipe to the surface, a squeeze job may be performed,

as described in an earlier section (see page 524) in connection with the recementing of a defective shutoff.

Some of the most difficult and uncertain cases are encountered in attempting to shut off water which occurs as intermediate water in a zone of productive oil-bearing strata or in the base of a thick productive formation. Here every precaution should be taken to avoid cementing the productive strata. In some cases, also, top waters are separated from the oil zone by only a few feet of impervious material and very accurate knowledge of the depths and thicknesses of strata is necessary to land the water string and cement it before it enters the oil zone, and still be assured of placing the plug so that it is continuous throughout the water-bearing interval.

When drilling in territory in which the stratigraphy is not definitely known in advance, a well will sometimes be drilled below the logical point for a water shutoff before the necessity for it becomes apparent. In such a case, it is necessary to withdraw the casing until the shoe is at the desired level and then plug or bridge over the lower portion of the hole before introducing the cement. An alternative plan would be to use a combination string and cement it through perforations, as described on page 521.

Importance of Stratigraphically Uniform Shutoffs in Contiguous Wells.—A study of the possibility of water migration from well to well



(*In part after R. P. McLaughlin, California State Mining Bureau, Department of Oil and Gas.*)

FIG. 210.—Illustrating manner in which water may migrate from one well to another.

through porous strata will indicate the importance of stratigraphic uniformity in the placing of water shutoffs. Figure 210 illustrates situations arising from failure on the part of the neighboring operators to recognize the necessity for cooperation in deciding upon the selection of a particular stratum in which to make all water shutoffs. Correlations for this purpose, and determination of landing depths for water strings, constitute an important aspect of systematic water exclusion. Such work should be entrusted to some state or semipublic technical commission rather than left to the whim of individual operators. In California the depth at which the water shutoff is to be made in every well is specified by the State Oil and Gas Supervisor or his deputy.

Locating the Source of Water in a Group of Flooded Wells

In many cases it is a difficult matter to determine the source of water which is finding its way into an oil sand. Occasionally, large quantities of water will be admitted to the productive sands through a single well, until neighboring wells are influenced, perhaps cutting off all production from an entire group within a few months' time. It is evident that such a condition will occasion large losses, and there will be ample justification for the expenditure of a considerable sum in repair work if by so doing the condition can be remedied. When such a situation presents itself, it usually requires a careful study of all of the available information to determine which well is at fault and, when this is done, to locate the source of the water.

In determining which well of a group is admitting water to the productive strata, recourse may be had to several methods of procedure. A close stratigraphical correlation of water shutoffs with the aid of a peg model may disclose the fact that in one well the cement plug provided to exclude top water has been placed too high, or that the well has been drilled into bottom water. A study of the drilling history of each well may disclose facts which will aid in reaching a conclusion. Perhaps a water string has corroded to such a degree that water has found admission, or it may be that a cement plug has disintegrated as a result of the use of unsound cement or by contact with reactive ground waters. Again, if the wells are producing from several different sands comprising a zone, an edge-water condition developing in one sand may occasion apparent flooding of others. A carefully kept series of production records giving the amounts of water and oil produced by each well of a group will be of great assistance in determining which well or wells were first influenced and which produce the largest percentage of water. Attention can then be focused on these as likely offenders. A study of fluid levels in a group of wells will often disclose the faulty well as the one having the highest fluid level.

Use of Dyes and Dissolved Salts as Flow Detectors.—It is occasionally possible to prove that water is flowing from one well to another by inserting an easily detected dye or chemical substance in the well into which the water is flowing, and observing its later appearance in the water pumped from surrounding wells. This is a test that may be applied after attention has been focused on the offending well of a group by a close study of the evidence.

The dyes commonly used are fluorescein, eosine, magenta and other fluorescent organic dyes. Fluorescein, which has a distinctive yellowish green color by reflected light, is apparently best adapted to the purpose.* It can be detected in water by the naked eye when present to the extent of 1 part in 40,000,000, and, with the aid of the fluoroscope, 1 part in 2,000,000,000 can be detected. Furthermore, it is not appreciably adsorbed by clays and may travel for a considerable distance underground without change in its physical properties. Eosine is a brick-red dye that is not quite so easily detected in minute quantities as fluorescein. The dye should be dissolved in a bucket of water and either poured into the well or lowered in a glass container on the bailer or a cable drilling bit. On reaching bottom, a blow with the dart of the bailer or with the bit breaks the container and liberates the dye. The amount of dye necessary will depend upon the quantity of water the wells are producing, and upon a consideration of the opportunity for diffusion and the concentration necessary to produce an easily detected color. Usually a great excess is used—from 15 to 100 lb.—as a precaution against loss through adsorption, diffusion and dissipation in other ways. Instances are on record where dyes used in this way have passed through the earth over distances as great as 900 ft. in about 3 hr. time.[1]

A similar use of various soluble salts, such as lithium, sodium, calcium or ammonium chlorides or nitrates, has been suggested, identification of the foreign substance in the ground water being effected by chemical analysis.

It should be pointed out that the use of dyes and other flow detectors in tracing the movement of underground water is more or less unsatisfactory since the results are too often negative. If the detector can be shown to have moved from one well to another, it will have served its purpose; but if the result is negative and the detector does not appear, there is always the uncertainty of whether or not some unforeseen factor has prevented it from having proper access to the water channels, or whether it has been subjected to conditions which may have changed its physical or chemical characteristics.

Success in Water Exclusion Requires Close Engineering Supervision. Some of the most intricate and difficult problems in oil-field development are encountered in the exclusion of water from wells, and every phase of the work must be under engineering control. Selection of the landing point of a water string should be based upon accurate information that can best be secured by coring, followed by engineering inspection of the cores with due regard to thickness, permeability and hardness of the stratum upon which dependence is placed for security against passage of water around the cement plug through the formation. The well must be properly conditioned and the conditions within the well must be accurately interpreted. The physical and chemical properties of the cement used must be determined. The space to be filled by the cement

* Dole, R.B., Use of Fluorescein in Study of Underground Waters, *U. S. Geol. Survey, Water Supply Paper* 160, 1996.

plug, the necessary volume of cement and the amount of accelerator or other reagent to use must be carefully computed. The proper proportions of cement and water in the mix and the volumes of water, cement slurry and mud fluid used in pumping down the mixture must be accurately measured. The procedure followed in mixing and placing the cement must be expeditious and must be so planned as to proceed with minimum likelihood of interruption or accident. Tests to determine the success or failure of the work must be conscientiously performed. If failure has resulted, accurate diagnosis of the reason therefor, estimation of conditions within the well and planning and conduct of the necessary remedial measures require engineering ability of a high order. All of this work is exacting and is properly placed under the immediate direction of a trained engineer, adequately informed on cement technology and familiar with the peculiar nature of the problems presented and the difficulties to be overcome.

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CHAPTER XIII

FISHING TOOLS AND METHODS

The recovery of tools, cables, pipe and rods which have become detached while in the well or which have been accidentally dropped into the well, and the repair of damaged casing, are operations that require the highest skill and ingenuity of the driller. In many cases, the completion of the well hinges upon success in recovering the lost equipment or making the necessary repairs. Days, weeks or even months may be spent and large sums of money expended in fishing operations.

A great variety of special tools have been devised to assist in such work, some of which are described and illustrated in the present chapter. Only the more common fishing tools will be discussed, and these but briefly, it being quite impossible, in the space available, adequately to describe all of the many tools that find application in fishing operations. Indeed, many of these tools are but rarely used; in some cases a tool will be made for a particular purpose and never used again. Only the largest operators can afford to own more than a limited assortment of such tools because of their great cost and limited use, and many operators make a practice of renting them from local supply dealers as they are needed. The technic of fishing is mastered by comparatively few drillers, and the industry is developing specialists in this work, who undertake the recovery of lost tools or the repair of damaged casing under contract.

One might suppose that the loss or breakage of a tool in the well, or the parting or collapse of a string of casing, is the result of carelessness and might be avoided by proper design and care in the conduct of the work. Although this is true to a large extent, it should be recognized that such accidents are a natural hazard; that they are inherent in the very nature of the work and therefore can never be entirely avoided. However, proper care in handling the equipment and frequent and thorough inspection of cables, casing, drill stem, tools and tool joints will greatly reduce the number and frequency of fishing jobs. Drilling cables and sand lines should be watched carefully for signs of weakness or unusual wear; drilling tools, drill stem and casing should be inspected for incipient cracks, particularly at welds; and no equipment or tools should be lowered into the well unless, as far as can be detected, they are in perfect condition. In anticipation of the inevitable fishing job, it is a good plan fully to record the dimensions of everything used about or in

the well so that information will be at hand for designing or selecting a suitable fishing tool.

We may classify the various fishing tools to be described according to the purposes for which they are intended or the nature of the operations in which they are used. There is a large group of fishing tools designed for recovering various parts of the string of cable drilling tools; another group is intended chiefly for taking hold on either the inside or outside of hollow cylindrical objects, such as casing, bailers or rotary drill stem; still others are designed to expand, cut, rip or perforate casing; and there is also a number of tools used in recovering or cutting hemp rope or steel cable in the well.

REPAIRING AND RECOVERING DAMAGED CASING

The difficulties encountered in handling casing in the well were outlined in Chap. XI. The methods of releasing frozen casing were there discussed, but the methods of repairing collapsed, parted and punctured casing were deferred until the present chapter.

Collapsed Casing

Use of the Casing Swage.—Collapsed casing, which has been partly flattened, dented or otherwise distorted from its original cylindrical form as a result of abnormal external pressure, can often be brought back to its original form by driving a casing swage through the collapsed section. Common types of casing swages are illustrated in Fig. 211. They have solid cylindrical bodies, pointed at the lower end and equipped at the upper end with a tool joint for connecting with the lower link of the jars. A spiral groove or water course is cut in the cylindrical surface to allow the well fluid to pass as the tool is lowered down through the pipe. The maximum diameter of the cylindrical body of the swage is but a fraction of an inch smaller than the diameter of the casing for which it is designed; thus, casing with a 10-in. inside diameter should permit the passage of a swage 9⅞ in. in diameter.

Special types of swages include the Hinterliter hollow swage and the Oilwell roller swage. The former has a passageway through it, so that it can be lowered through a stream of flowing gas, water or oil. The roller swage is designed to reduce the great friction characteristic of most swaging operations, being equipped with a series of small rollers mounted on horizontal pins with the outer cylindrical surfaces of the rollers projecting slightly beyond the body of the tool.

The swage is attached below long-stroke fishing jars, and the latter are attached to the lower end of the drill stem. The tools, thus connected, are lowered into the well until the swage encounters the collapsed or dented portion of the pipe. The weight of the tools is then transferred to the walking beam, the jars being permitted to telescope and strike on the downstroke. As the swage is driven ahead by the impact of the stem and jars, the temper screw is let out sufficiently to keep the jars striking on the lower end of the downstroke. When the swage has been driven

through the collapsed section and has entered the undisturbed pipe below, the tools swing freely, resulting in an unmistakable change in vibration and cable tension. The swage must now be drawn back through the collapsed section and will probably have to be jarred back by permitting the jars to strike on the upstroke. The swage should be driven down and back through the pipe until it can be pulled through without jarring.

When it is thought that the pipe is badly flattened, it is preferable to drive a swage of smaller diameter through first; the full diameter of the pipe is attained through the use of successively larger swages. The swage sometimes becomes wedged in the casing, and if the pipe is split, either by collapse or by the pressure of the swage, a most difficult situation may result through loose debris entering above the swage and wedging about it.

Recovering Parted Casing

When a string of casing has pulled apart in the well as a result of a defective joint, insufficient thickness of metal or severe tensional strain—as in attempting to pull it out of the well when the lower end is frozen—or when it has been purposely parted with the aid of a casing cutter, ripper or explosives, any of several different tools may be used in recovering the lower end. If the condition of the well and the casing permits of withdrawing the pipe to the surface to join the parted ends, this method is generally preferred and for this purpose use may be made of either a casing spear, which takes hold inside of the pipe, or a casing bowl or overshot, which takes hold on the outside. If there is reason to expect that the upper end of the parted column is splintered or irregularly fractured, as often happens when casing is parted with explosives, a mandrel socket may be preferable. If it is considered best not to remove the parted string from the well, connection may be made with it by a new string lowered from the surface, with a die nipple placed on the lower end.

Use of the Casing Spear.—There are many types of casing spears designed for taking hold on the inside of a column of pipe, but they can all be classified into two groups: (1) bulldog spears, which have no mechanism for releasing the spear once it takes hold, and (2) trip spears, which may be readily released, either by turning the tubing on which they are lowered, or by driving down upon them with the fishing jars.

Common forms of casing spears are illustrated in Fig. 211. They consist usually of a substantial cylindrical steel body, pointed somewhat at the lower end to guide the tool into the pipe which it is to recover, and equipped with a pin joint at the upper end for connection to the fishing jars or drill stem. Inclined planes are machined out of the cylindrical body for either two or four slips, the slips operating in grooves and keyed to a mandrel extending up through the body of the tool. In the case of the trip spear, the mechanism controlling release of the slips must be built inside of, or below, or above, the main body of the tool and often consists of a spring device operated by a latch or trigger, which can be tripped by revolving the tool or by driving down upon it with the jars.

In using a spear to recover parted casing, the tool is screwed to a mandrel and the latter is attached to the lower end of the jars. If the spear to be used is of the bulldog

type or a type of trip spear that is released by the jars, the fishing string thus assembled may be lowered on the drilling cable. If a trip spear of the type that is released by turning is to be used, it must be lowered on a string of tubing and a substitute is used in connecting with the fishing string above the jars. When the tool has entered the open end of the parted pipe, it is raised until the slips slide down the beveled supports and bind against the walls of the pipe[1] (see Fig. 212).

A trip spear should be used in preference to one of the bulldog type when there is any possibility of the casing being frozen or otherwise difficult to remove from the well. A bulldog spear can be driven farther into a pipe but cannot be pulled out once it has been lowered, unless the pipe comes with it, without damaging either the spear or the pipe. Even the trip spears are apt to become "bulldogged" in the pipe

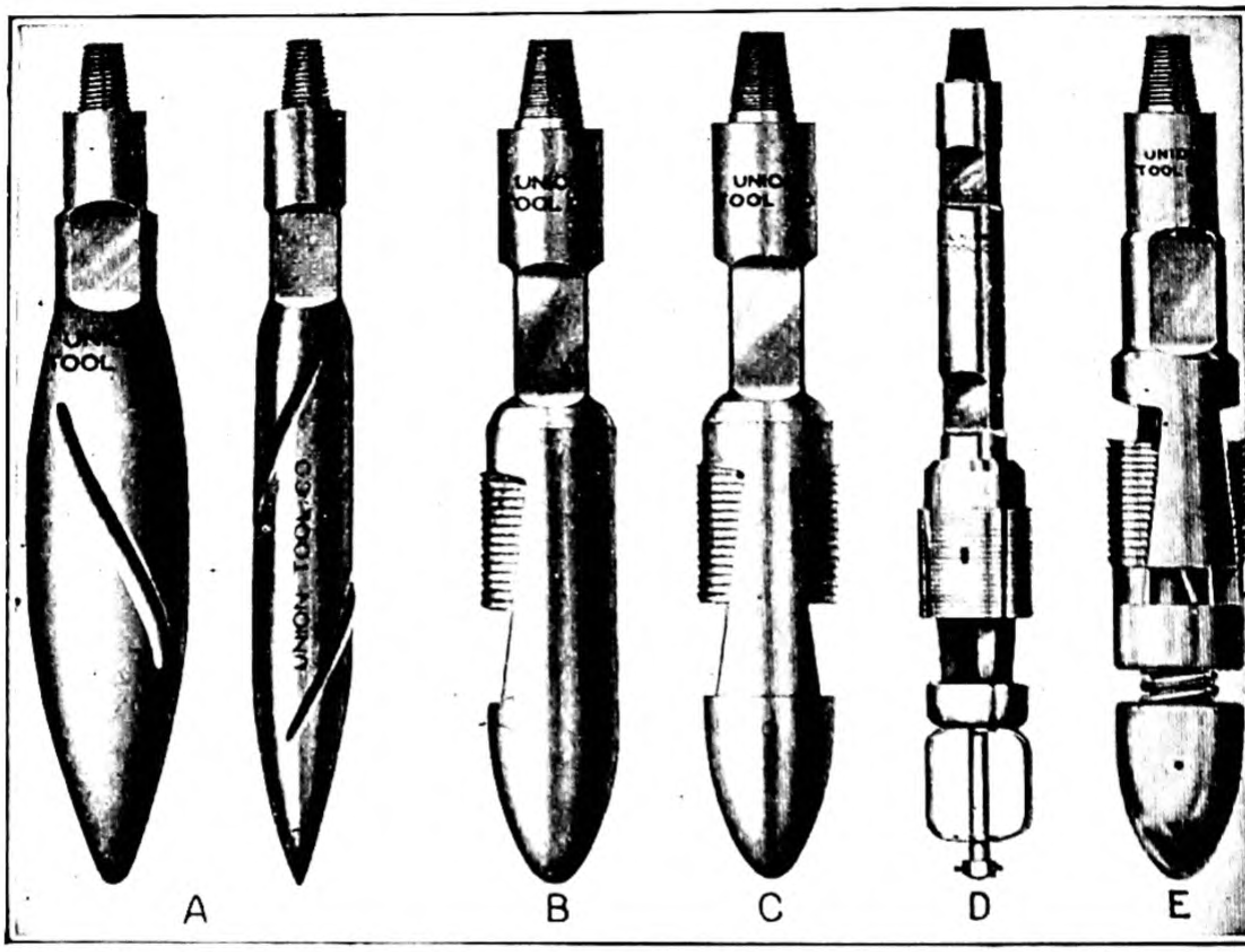
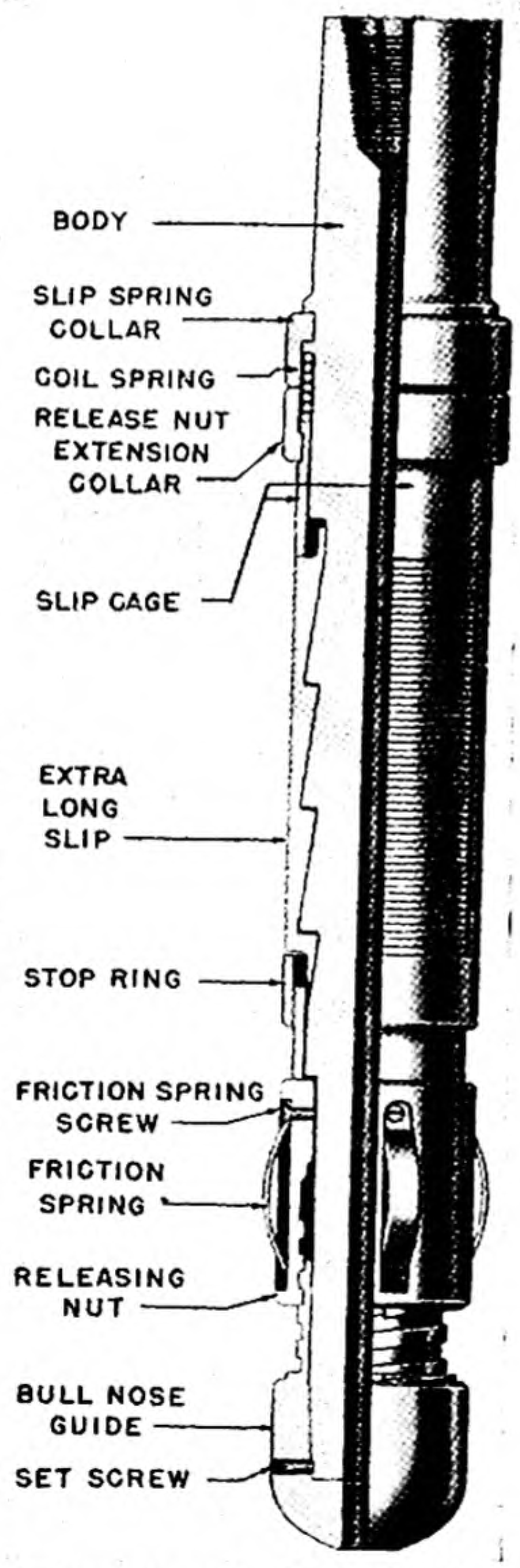


FIG. 211.—Types of casing swages and spears. *A*, casing swages; *B*, bulldog single-slip spear; *C*, bulldog double-slip spear; *D*, drive-down trip spear; *E*, Fox trip spear.

by failure of the tripping mechanism to work properly or by caving of material from the walls above. When it is necessary to break the hold of a spear, the slips can often be worn smooth by hitching them onto the beam and jarring both up and down, rasping the slips against the pipe. Such action, however, is apt to damage the pipe. In some cases the slips break and fall into the well so that the main body of the tool can be withdrawn. The slips can usually be broken off if necessary, in order to remove the tool, by driving the spear down until it passes below the casing shoe and then jerking it up so that the slips strike the lower edge of the shoe. Pressure of the slips against the casing is apt to cause bulging or splitting of the metal. For this reason, the position of the spear should be changed occasionally.

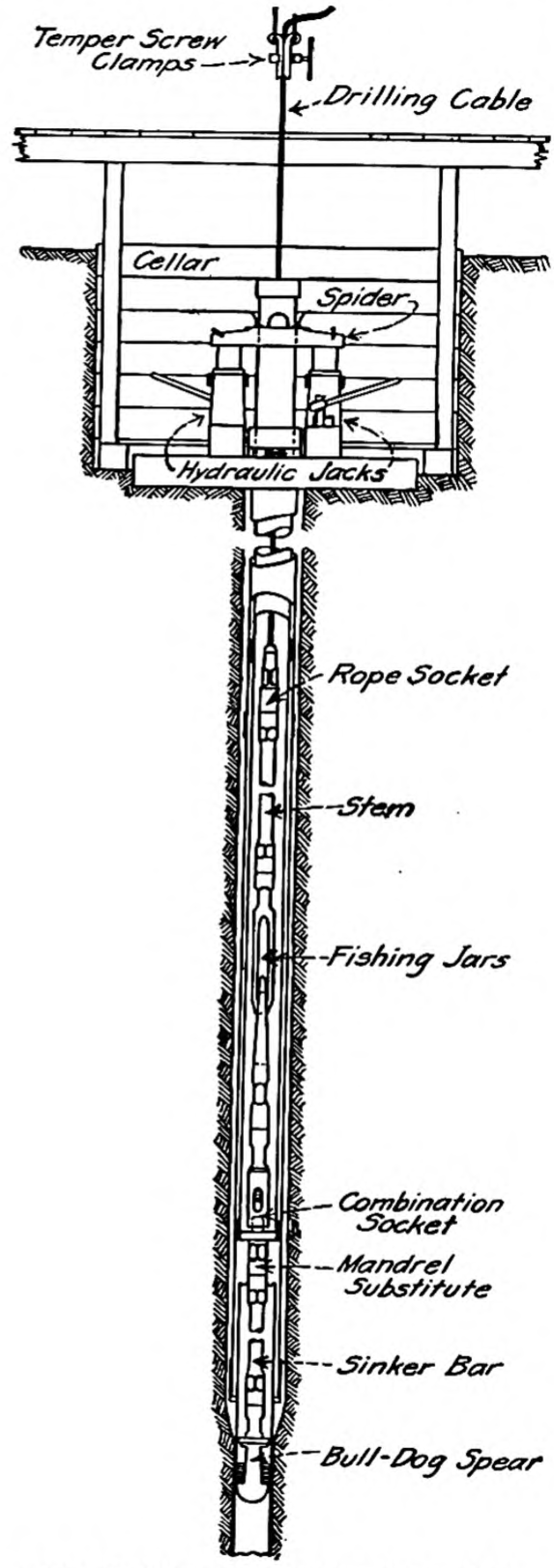
The use of a casing spear in jarring on frozen pipe has already been described (see page 441). A somewhat similar plan is occasionally followed when the lower end of a parted string of pipe has become frozen in the well (see Fig. 213). A spear is attached to the lower end of a short stem, and the latter is attached at its upper end to a substitute equipped with a mandrel projecting upward at its center. The sub-

stitute is screwed into a casing collar, and the tools thus assembled are lowered on a column of casing of the same size as the parted string in the well. When the spear has entered the upper end of the parted section of pipe and has taken hold, two hydraulic jacks are rigged under the casing spider in the cellar and tension is applied to the pipe. A second fishing string, consisting of a combination socket (pages 549–550), fishing jars, stem and rope socket, is then lowered on the drilling cable and a hold taken with the combination socket on the mandrel, which projects above the substitute. The latter string is then hitched onto the walking beam and the stroke



(*Courtesy of McCullough Tool Co.*)

Fig. 212.—McCullough rotary releasing spear.



(*After T. Curtin in U. S. Bur. Mines Bull. 182.*)

Fig. 213.—Fishing string for applying combined jar and pull on casing.

adjusted so that the jars strike on the upstroke. This combined lifting force, or pull of the hydraulic jacks, and jarring action are often effective in freeing the casing.

In addition to its use in recovering casing, the spear may also be used in recovering a lost bailer the bail of which has pulled out, or a rotary drill stem, well tubing or any hollow cylindrical object to the inside of which access may be had from above.

Use of the Casing Bowl.—The casing bowl is a hollow, cylindrical tool equipped with internally placed slips which can be lowered over a cylindrical object and take a hold on the outer surface. One successful type of casing bowl (see Fig. 214) has three slender slips mounted in machined inclined grooves on the inner surface of a steel cylinder. If the parted section of pipe has no collar on the top joint, a bowl of proper size can be lowered over the end and a hold taken sufficient to withstand considerable pulling. It may be used instead of a die coupling or collar (see page 541) in cases where it is desired merely to connect with a detached string of pipe in the well without pulling it out. This tool has not sufficient strength to permit of driving, and is not watertight.

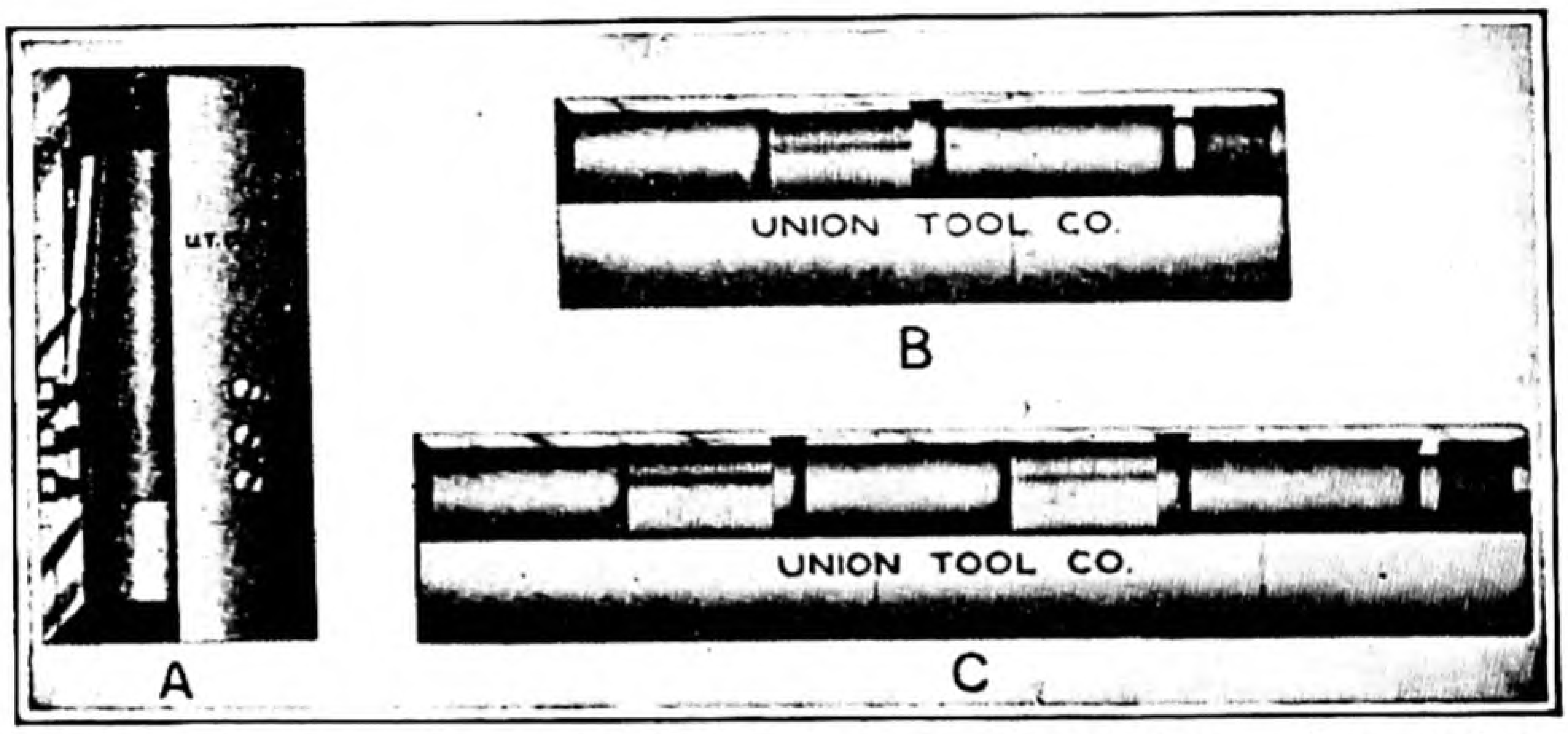


FIG. 214.—Fishing tools for recovering casing or rotary drill pipe. *A*, overshot; *B*, single-slip casing bowl; *C*, double-slip casing bowl.

A rotary casing bowl manufactured by the Hinderliter Tool Company is equipped with a slender slip designed to engage when the tool is turned to the left. The tool is available in two models, one of which operates on the inside of the detached pipe and the other on the outside.

Use of the Overshot.—If a collar has been left on or near the upper end of a parted string of casing, the overshot may be used in recovering it. This is a tool equipped with three or four flat springs held erect within a steel bowl (see Fig. 214). It is suspended on the lower end of a column of pipe of greater diameter than the detached string in the well. As it is lowered, the bowl guides the tool over the upper end and the springs press inward against the parted string. It continues to descend, telescoping over the parted section of pipe, until the springs slip under the lower edge of the collar, when on pulling up on the tool a hold is taken sufficient to stand severe strain. The overshot is widely used in recovering rotary drill stem that has twisted off while in the well and is also useful in picking up tubing or casing that has been dropped and is broken or crooked.

Use of the Bell Socket or Mandrel Socket.—When casing has parted and the upper end of the detached column is ragged or fractured so that the tools described above are not effective, the mandrel socket may be used. This consists of a long, hollow, tapered cone-shaped socket, through which extends a mandrel with an egg-shaped knob on the lower end. The mandrel is free to slide up and down within the socket, and on the upper end a pin joint is forged for connecting with the jars. A

shoulder turned on the mandrel just below the tool joint permits of driving down on the flattened top of the socket with the aid of the jars (see Fig. 215).

As the tool is lowered below fishing jars and a drill stem on the drilling cable, the socket passes over, and the mandrel inside of, the detached column of pipe. Driving down with the jars, with the mandrel extended below the socket as shown in Fig.

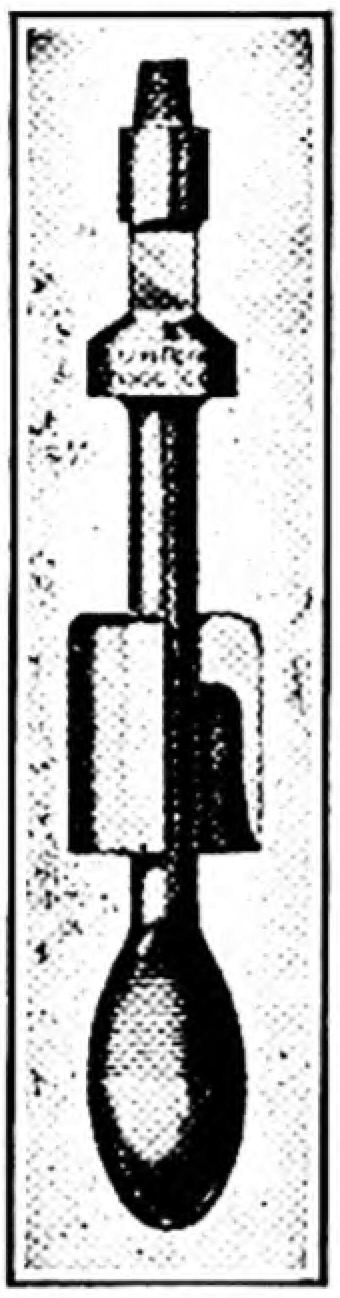


FIG. 215.—Bell socket.

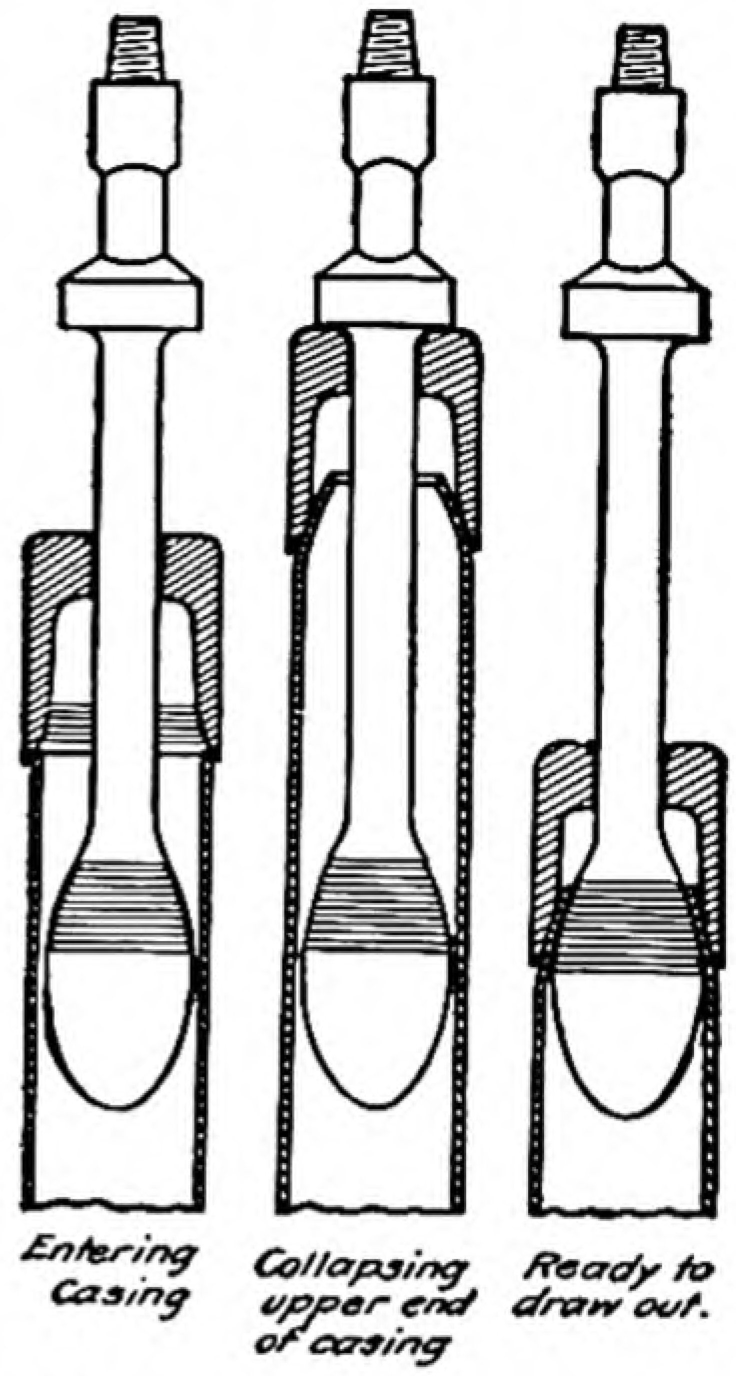


FIG. 216.—Application of bell socket.

216, the upper end of the detached pipe is collapsed and forced into the conical socket, thus partly closing the end of the pipe. On drawing up the tools, the knob on the lower end of the mandrel, now too large to pass through, grips the collapsed pipe on the inside and presses it against the inner face of the mandrel. The friction hold thus secured is sufficient to withdraw the pipe if it is free to come.

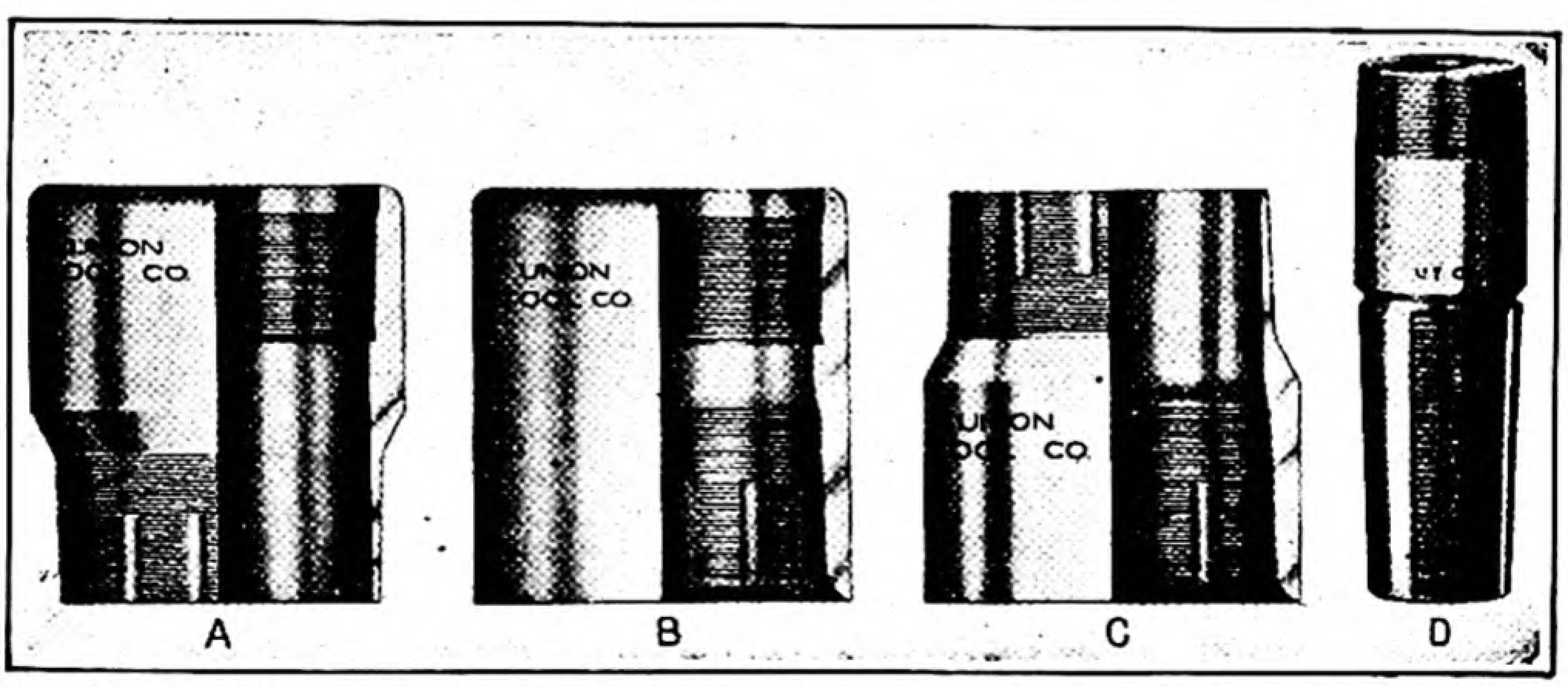


FIG 217.—Die nipples, collars and tap for taking hold of parted casing. *A*, die nipple; *B*, die collar; *C*, combined die nipple and collar; *D*, fishing tap.

Use of the Die Nipple and Die Collar.—Steel die nipples and die collars are used to recut threads on a detached column of pipe in the well, and may also serve as a coupling after the connection has been established (see Fig. 217). The die nipple is designed to cut a thread on the inside of a pipe or inside of a casing collar, while the die collar fits over the pipe and cuts a thread on the outside. A combination nipple

is designed to operate inside of the pipe on one end, and outside on the other. These tools are made of casehardened tool steel, too brittle to stand driving, although considerable tension may be applied if pulling is necessary. Aside from their use in cutting threads, they may be left as a permanent coupling in a string of pipe if, for any reason, it is considered inadvisable to pull the pipe out of the well after a connection has been effected. Because of the vertical grooves left in the cutting teeth for the escape of metal cuttings, die nipples and collars are not watertight and should not be left permanently in a water string. If a die coupling is to be used to couple two parts of a string of pipe permanently, care should be taken to select one large enough in inside diameter to pass the various drilling tools that must be subsequently lowered through it.

Die collars and nipples are lowered on the bottom of a string of pipe of the same size as the parted pipe to be recovered. When the tool rests lightly upon the upper end of the detached column, the "fishing string" is turned slightly until the pipe drops into position and is ready for screwing. Pipe tongs are then applied to the fishing string with the aid of a jerk line to the crank, the weight of the upper pipe being permitted to rest upon the detached pipe. While the nipple or collar is screwed on with the engine power, a second pair of pipe tongs is used to prevent the pipe from springing back as a result of torsional strain in the pipe when the slack comes in the jerk line with each revolution of the crank. A reference mark is made on the pipe near the derrick floor to note the distance that the pipe settles after screwing begins, this being a measure of the length of thread cut unless some of the couplings in the fishing string take up. As the die makes headway, a continuous increase in power is necessary to turn it. The point at which to stop turning is always more or less uncertain but may be inferred from the amount of tension on the tongs and the distance that the pipe has settled. The two strings of pipe are thus firmly fastened together and in condition to be pulled if desired.

Cutting or Parting Casing in the Well

Occasionally it becomes necessary to detach a section of pipe in the well. This is often done when a string of pipe becomes frozen and the lower part of the column must be sidetracked (see page 446); and in salvaging pipe during the casing of a well or in abandoning it, parting of the casing is commonly practiced. A column of pipe may be cut apart while in the well with a special tool, called a "casing cutter," which is lowered through the pipe to the desired point and applied against the inner walls; or slits may be cut in the pipe with a casing ripper until it is so weakened that it can be readily pulled apart; or a charge of dynamite or nitroglycerin sufficient to part the pipe may be detonated in the well at the desired depth.

Cutting Pipe with the Casing Cutter.—The casing cutter is very similar in principle to the ordinary plumber's pipe cutter, except that it is designed to operate from the inside of the pipe instead of on the outside. The casing cutter consists essentially of a heavy cylindrical steel body into which are mortised a number of sliding steel blocks on the outer edges of which small circular, disk-shaped wheels of steel are mounted (see Fig. 218). The latter revolve freely in a horizontal plane on small metal pins set in the outer ends of the sliding blocks. A tapered steel mandrel oper-

ates through a cylindrical hole through the axis of the tool in such a way that when the mandrel is pressed down, it bears against the inner ends of the sliding blocks, forcing them horizontally outward. The casing cutter is lowered, screwed to the lower end of the column of tubing, which must, of course, be small enough to pass freely through the casing to be cut.

Before lowering the cutter, the "sag" should be taken out of the casing and a moderate tension applied and maintained by means of the elevators or casing spider. There should be enough tension in the pipe to cause the upper end to "jump" when the pipe is cut, thus indicating completion of the work to the operator. With the casing under tension, the cutter is lowered to the desired depth on its tubing. The mandrel is then connected to the lower end of long-stroke jars small enough to enter the tubing, and from two to four sucker rods are placed above the jars to give weight to the upper link. The mandrel, jars and rods, thus connected, are lowered on the sand line through the tubing until the tapered mandrel enters its recess in the casing cutter and encounters the inner ends of the sliding steel blocks that have been pressed in during the descent of the tool. The tubing is then turned by hand. The weight of the rods above the mandrel forces the blocks containing the knives out against the casing. Sometimes this weight is sufficient for the work, but when it is not and the cutter turns with so little effort that the operator is convinced that it is making little progress, the mandrel may be driven farther into the tool with the aid of the jars, by raising and dropping the sand line either by hand or with the engine power. The mandrel should not be driven between the blocks too tightly, or the tubing cannot be turned.

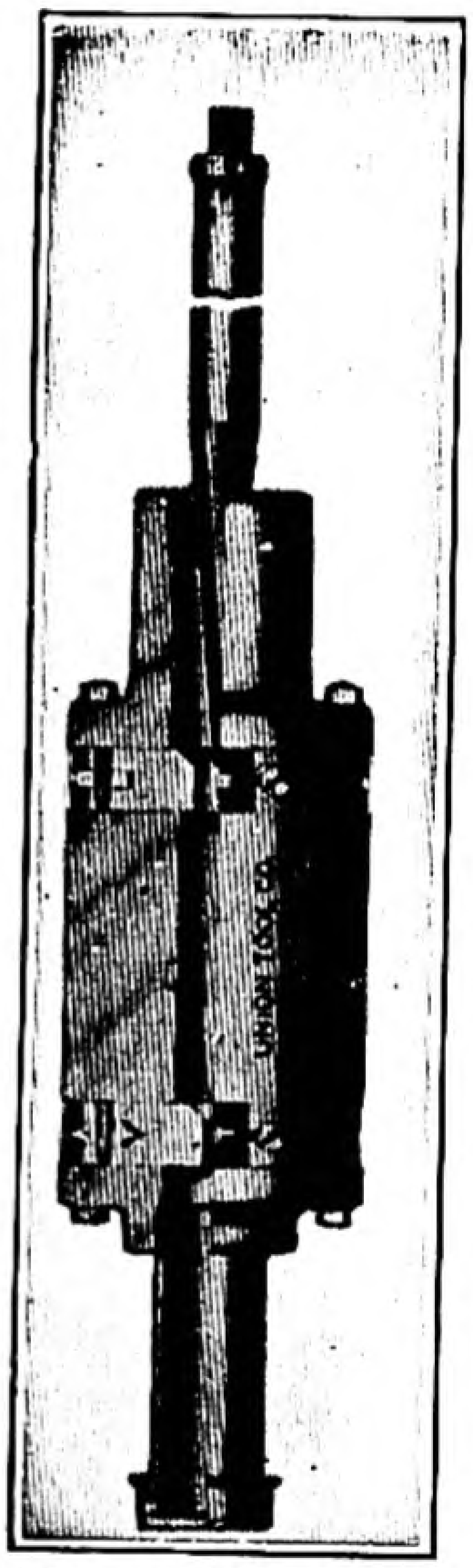


FIG. 218.—Casing cutter.

Usually from 20 to 40 min. turning of the tubing will be necessary to cut the casing, the upper end jumping slightly when the operation is completed because of the tension in the pipe. The mandrel and rods should then be pulled and the tubing gently raised until the sliding blocks containing the cutters are forced back into their recesses, when the cutter can readily be withdrawn to the surface.

Use of the Casing Splitter.—Lowered to the desired depth in a column of casing to be parted, the casing splitter, or ripper, may be applied in cutting vertical slits in the pipe. Such action greatly weakens the casing, particularly if applied to the joints under the collars, so that the column can be readily pulled apart by applying moderate tension at the upper end.

The tool consists of a substantial steel body through which a recess is cut for a pointed steel knife mounted on a sliding block which slides on a steel pin in two inclined grooves (see Fig. 219). A pin joint is provided at the top of the tool for connecting with a fishing string consisting of long-stroke jars, drill stem and rope socket. A mandrel extends down through the axis of the tool and is attached to the sliding block which supports the knife. On the lower end of the mandrel a heavy spring is placed, which when released bears against the inner walls of the casing. There are single-knife and double-knife patterns, the latter type cutting two slots at once, 180 deg. apart on the circumference of the pipe.

Before lowering the splitter into the casing, the spring (see Fig. 219) is raised on the mandrel by compressing a small trigger at the lower end of the mandrel.[1] As the tool is lowered through the casing, there is enough pipe friction upon the spring to prevent it from dropping below the trip trigger. When the tool has been

lowered to the desired depth, it is then raised a few feet, thus drawing the mandrel up through the spring; the mandrel tripper snaps into place above the lower edge of the spring and the tool is tripped. The knife block is now held in the upper end of the inclined grooves by the spring pressure. The drilling cable on which the tools are lowered is then hitched to the beam, the play of the jars being adjusted so that they strike on the downstroke but not on the upstroke. With the first stroke of the jars the knife punches a hole through the casing, and succeeding blows will cause the knife to cut a slit vertically down the pipe. The progress of the knife will be retarded on encountering a casing coupling but not stopped. A slight tension is held on the pipe while the tool is in operation. When a coupling is split, the pipe can be readily pulled apart, although the coupling sometimes fails to spread enough to permit pulling without first driving down on the upper end of the column with the drive clamps and head. As the casing splitter is withdrawn, the knife block is forced down the inclined slots and away from the casing, compressing the mandrel against the spring. If necessary to effect withdrawal, the knife can readily be broken by driving up with the jars.

FIG. 219.—Casing ripper.

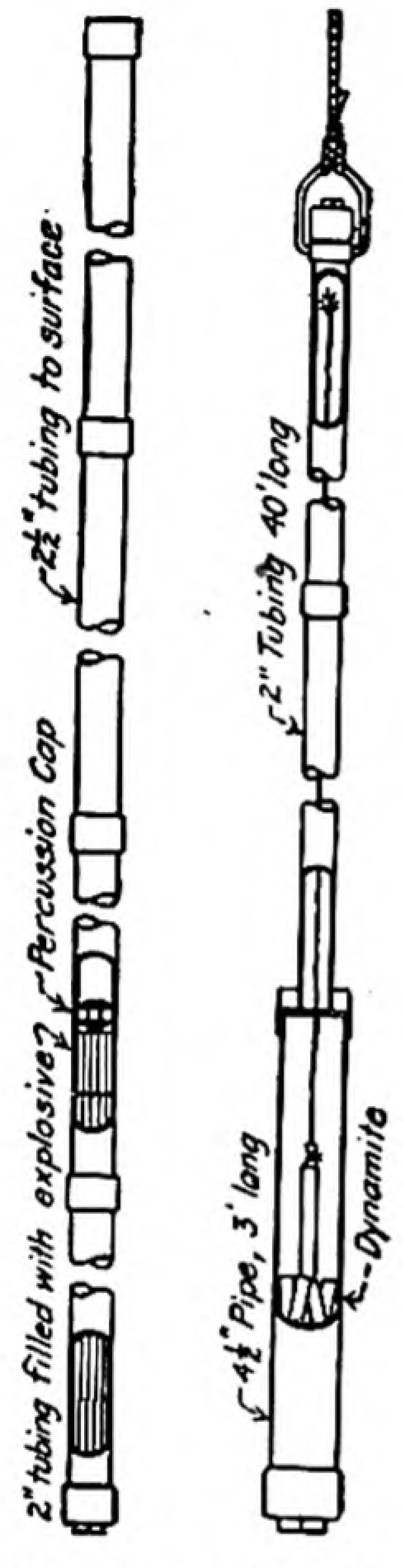
The casing splitter is commonly used in salvaging casing when a well is to be abandoned, and when the work involved in freeing an entire string of pipe would be too expensive. The tool may also be used for perforating pipe opposite an oil sand, though it is not so satisfactory for this purpose as a somewhat similar tool called a "casing perforator." Casing perforators are described on page 571.

Use of Explosives in Parting Casing in the Well.—The simplest and cheapest method of parting a string of casing in the well is by the use of explosives. If a well is to be abandoned, the operator is anxious to salvage as much of the casing as possible at the lowest cost. An effort is first made to pull the casing. If it is frozen so that it cannot be readily pulled, explosives may be applied, parting the pipe a short distance above the shoe. If the casing still resists pulling, another shot may be fired some distance above the first and blasting continued at successively higher points until the pipe can be pulled. Another frequent use of explosives in parting casing is found in freeing a water string from a cement plug when the shutoff has been unsuccessful. The lower end of the pipe may be shot to pieces so that the upper can be withdrawn and a new shoe attached. The lower part of the hole must then be redrilled and a shutoff attempted at a lower horizon.

Dynamite, blasting gelatin or nitroglycerin may be the explosive used, though blasting gelatin or ordinary stick dynamite is ordinarily preferred, being a safer and more reliable type of explosive than nitroglycerin. The explosive is charged into a suitable container or torpedo and is detonated with a blasting cap of fulminate of mercury, fired electrically, with a fuse or squib or by the impact of a go-devil dropped from the surface. Electrical firing is safest, but a fuse or squib may be used with security if care is taken to make certain that the charge is properly placed and timed. The risks involved in handling explosives are appreciated by most operators, and it is customary to employ someone skilled in the use of explosives when such work is done. Often it is done under contract by men who specialize in well shooting. The danger is not only to the workmen but to the well also, for a premature explosion at some point above the desired horizon will wreck the casing,

perhaps causing caving of the walls and burial of the well equipment, in some cases even necessitating abandonment of the well.

If dynamite is to be used, it should be lowered on the sand line to the desired point in a container made of casing or tubing. From 20 to 40 sticks of 60 per cent dynamite are carefully packed into a piece of casing 4½ in. in diameter and 3 ft. long, with a coupling on each end and a plug in the lower coupling. In the top coupling a 4½- by 2-in. bushing is placed to connect with two joints (about 40 ft.) of 2-in. tubing, which contains the fuse. A plug is placed in the top of the tubing so that the entire container is watertight. A small bail at the top provides a means of connecting with the sand line (see Fig. 220). A length of fuse is cut sufficient to allow ample time for lowering the explosive after lighting at the surface, and a detonating cap is crimped on one end and inserted in a stick of the explosive in the usual way. With the container charged with explosive and suspended in the well so that the top of the tubing is 2 or 3 ft. above the derrick floor, the squib is lowered through the tubing by means of the fuse until it rests upon the top of the explosive in the 4½-in. container. The fuse is then ignited, the plug screwed into the top of the tubing and the container with its charge is carefully lowered to the desired point in the well. The explosive container and tubing will be shattered by the explosion, but the sand line will ordinarily be uninjured.



(After T. Curtin in U. S. Bur. Mines Bull. 182.)

FIG. 220.—Use of tubing as dynamite container.

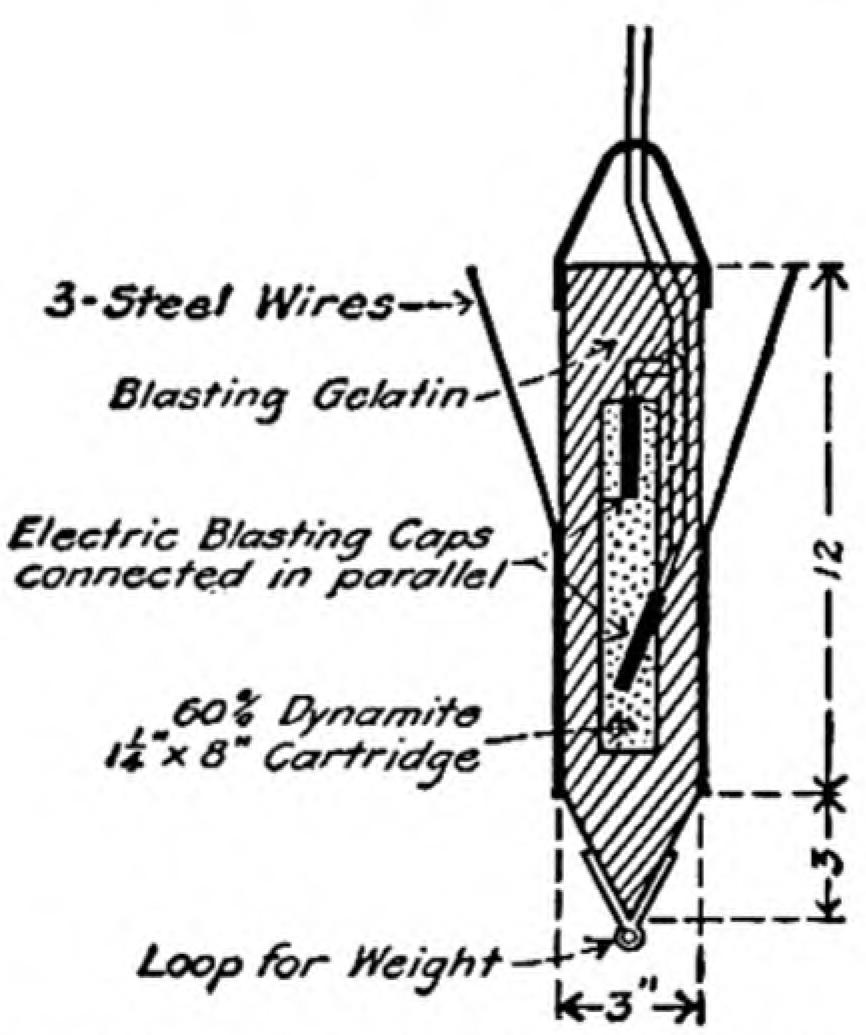


FIG. 221.—Hercules electric detonating squib.

When it is desired to shatter a considerable length of casing, say, several hundred feet—as in shooting a section of cemented pipe—a string of 2½-in. tubing, plugged at top and bottom and as long as the section of pipe to be shattered, can be filled with explosive and detonated (see Fig. 220). In this case it might be preferable to fire the charge by means of a squib dropped upon the charge from the surface (see page 589).

In firing electrically, the explosive should be placed in tubing or casing or in a torpedo shell, as described above, with an electric detonator on top of the charge (see Figs. 221 and 222). Two insulated copper wires connecting with the squib are carried through a watertight joint in the plug, which encloses the top of the container, and

are bound with cord or friction tape at intervals to the sand line on which the explosive is lowered. After the charge has reached the desired point in the well, the two wires are connected with a blasting machine or to a two-pole switch placed in the lighting circuit and the charge is fired. There is less danger of premature explosion when this method of firing is employed, and successful detonation of the charge is more certain than in firing by either of the other methods described.

In the California fields,* most well shooting is done with blasting gelatin, which is less sensitive than 60 per cent dynamite and therefore safer to use in practice. The blasting gelatin is carefully tamped into a cylindrical torpedo shell made of No. 28 galvanized sheet iron, with a few sticks of 60 per cent dynamite scattered through the charge to ensure complete detonation of the gelatin (see Fig. 223). Electrical firing is preferred, a special 150-grain fulminate of mercury cap being used for detonation. Generally more than one cap is used, in order to detonate the entire mass completely, one cap being used for every 3 lin. ft. of the length of the shell. The upper end of the torpedo should be closed with a pressure-resisting seal, to prevent compression of the gelatin, which, it is thought, may be the cause of premature explosions. A "shooting iron," consisting of a joint or two of 2- or 3-in. tubing, is suspended over the sand line, just above the torpedo, to prevent the line from being shot into a tangled mass by the explosion. The caps used are connected in parallel with the firing circuit and symmetrically placed throughout the charge. The torpedo is usually lowered on the sand line, which forms one wire of the circuit, while an insulated copper wire bound to the sand line at intervals completes

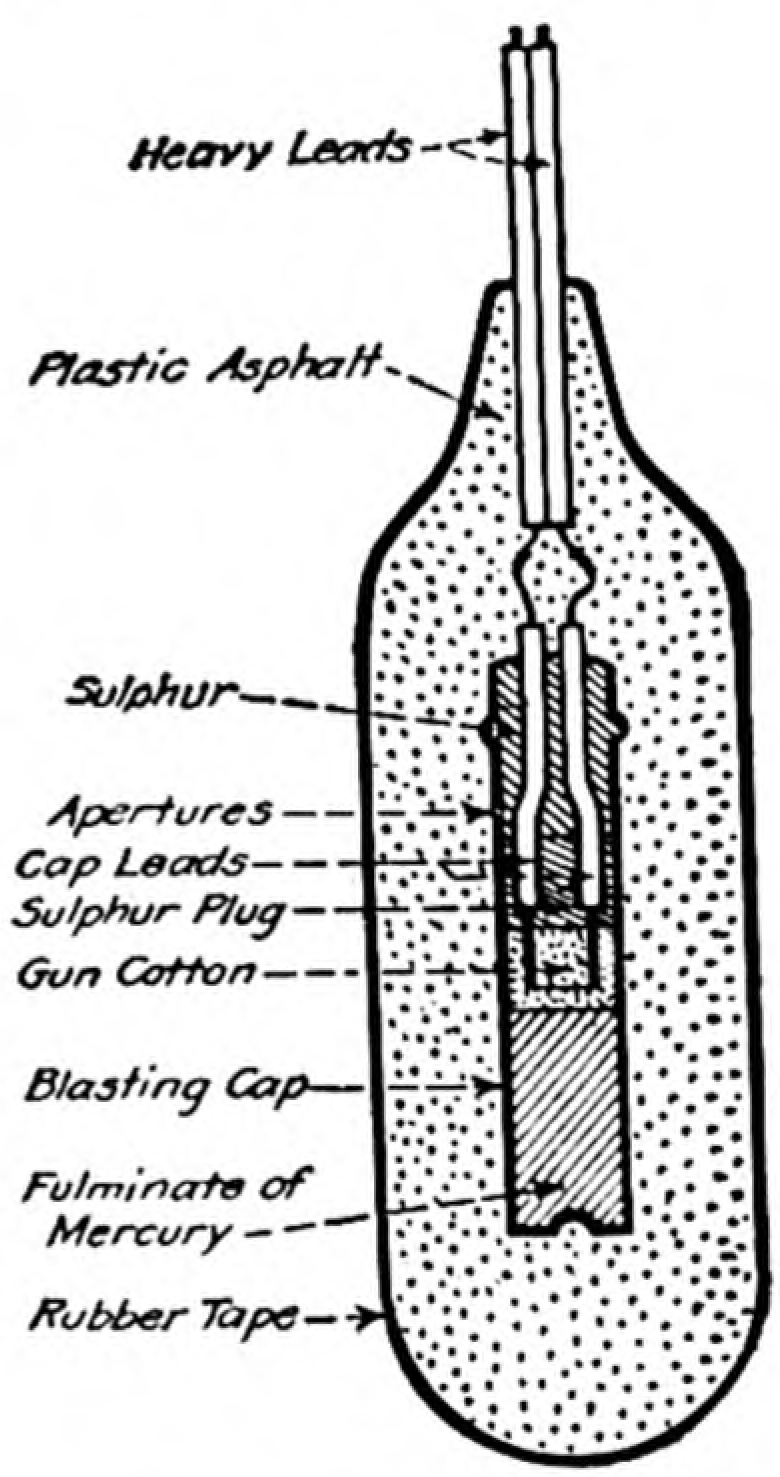


FIG. 222.—Allison electric detonating squib.

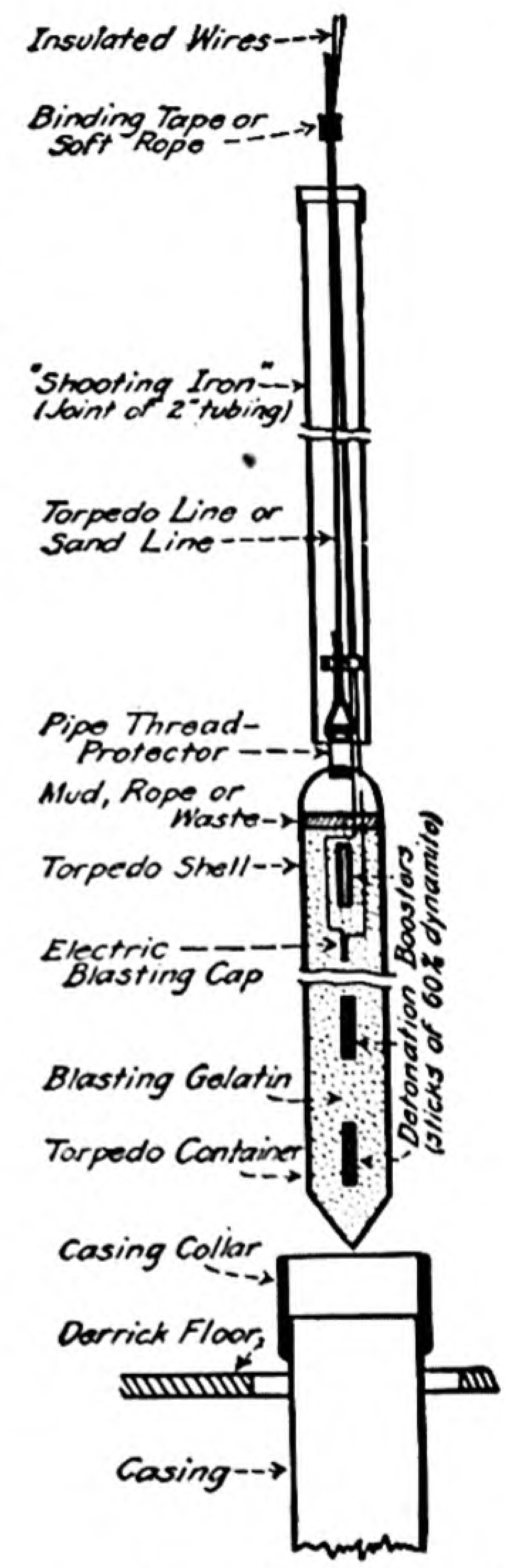


FIG. 223.—Manner of loading and lowering torpedo.

* GOLDMAN, F., and STEAD, G. D., Oil-well Shooting, a thesis prepared under the direction of the Author, University of California, 1923.

the connection with the blasting machine or electric circuit at the surface. If there is oil in the well, there is a possibility of the electrical connection with the sand line becoming insulated, causing a misfire, and for this reason some well shooters prefer to use two separate wires for the electrical circuit instead of depending upon the sand line to form one lead. Before the charge is lowered, and before firing, the circuits should be tested with a sensitive galvanometer and a silver chloride cell. The latter does not produce sufficient current to fire the caps, but, as an added precaution, a suitable resistance is maintained in the circuit while testing.

Further description of the use of explosives in wells will be found in Chap. XIV.

RECOVERING STEEL AND HEMP CABLE

When the cable drilling tools are used, the drilling cable or sand line will occasionally break with the tools or the bailer in the well. If the break has occurred at some distance above the point of connection, the parted end will fall to the bottom in a twisted mass on top of the tools or bailer and must be recovered with the aid of a rope grab or spear. Occasionally, too, the drilling tools or bailer will become lodged in the well, as a result either of the walls caving or of the upper end of the string catching under the casing shoe. In such a case it may be necessary to cut the drilling cable or sand line in the well directly above the rope socket or bailer bail, so that other fishing tools may have ready access to the tools or bailer. For this purpose various types of rope knives are used. The forms of rope grabs, spears and knives used will vary somewhat with the kind of rope to be recovered, that is, whether it is of manila hemp or steel wire.

Rope Grabs and Spears.—A group of representative rope grabs and spears are illustrated in Fig. 224. It will be noted that they consist of one or more prongs with a number of upturned, sharp-pointed thorns or spikes projecting from them. A pin joint at the top provides a means of connecting with a fishing string consisting of long-stroke jars, drill stem and rope socket. The tool is lowered and spudded up and down on the cable until the prongs and spikes take hold and the rope can be drawn to the surface. If the broken end of the cable is not long enough to reach to the surface, the hold of the spear is usually sufficient to support the tools or bailer so that it can also be withdrawn. The "mouse trap," illustrated in Fig. 224, serves a similar purpose. This tool is lowered on three joints of tubing. A few feet of cable will always enter the lower end, the small hinged wickers take hold and, as the upper part of the tool is pulled up, the rope is drawn into the tubing. Sixty-five feet of cable can be removed with each run.

Rope Knives.—If the bailer or tools become lodged in the well and it becomes necessary to cut the drilling cable or sand line to permit of access being had by tools employed in loosening them, one of several types of rope knives may be used. These knives vary from simple V- or hook-shaped bars with sharpened edges, or chisel- and shear-shaped "choppers" used on hemp cable, to the stronger and more elaborate wire-line knives which require the use of auxiliary jars and sinkers. The hemp knives and choppers are lowered with a sinker bar on the end of the sand line.

The resistant nature of steel wire cables requires a knife of greater strength and more positive manner of application. Such tools are usually lowered over the cable

to be cut, and the knives are tripped or driven into cutting position on striking the rope socket or bailer bail. A common form (see Fig. 224*G*) has one or more "dogs" with sharpened edges, so pivoted that they remain in a vertical position as long as the tool is being lowered, but fall into horizontal cutting position and bear against the cable as soon as they are raised. Another type (see Fig. 224*E*) has a pivoted hollow disk, sharpened on the inner edge, which is held in horizontal position and free

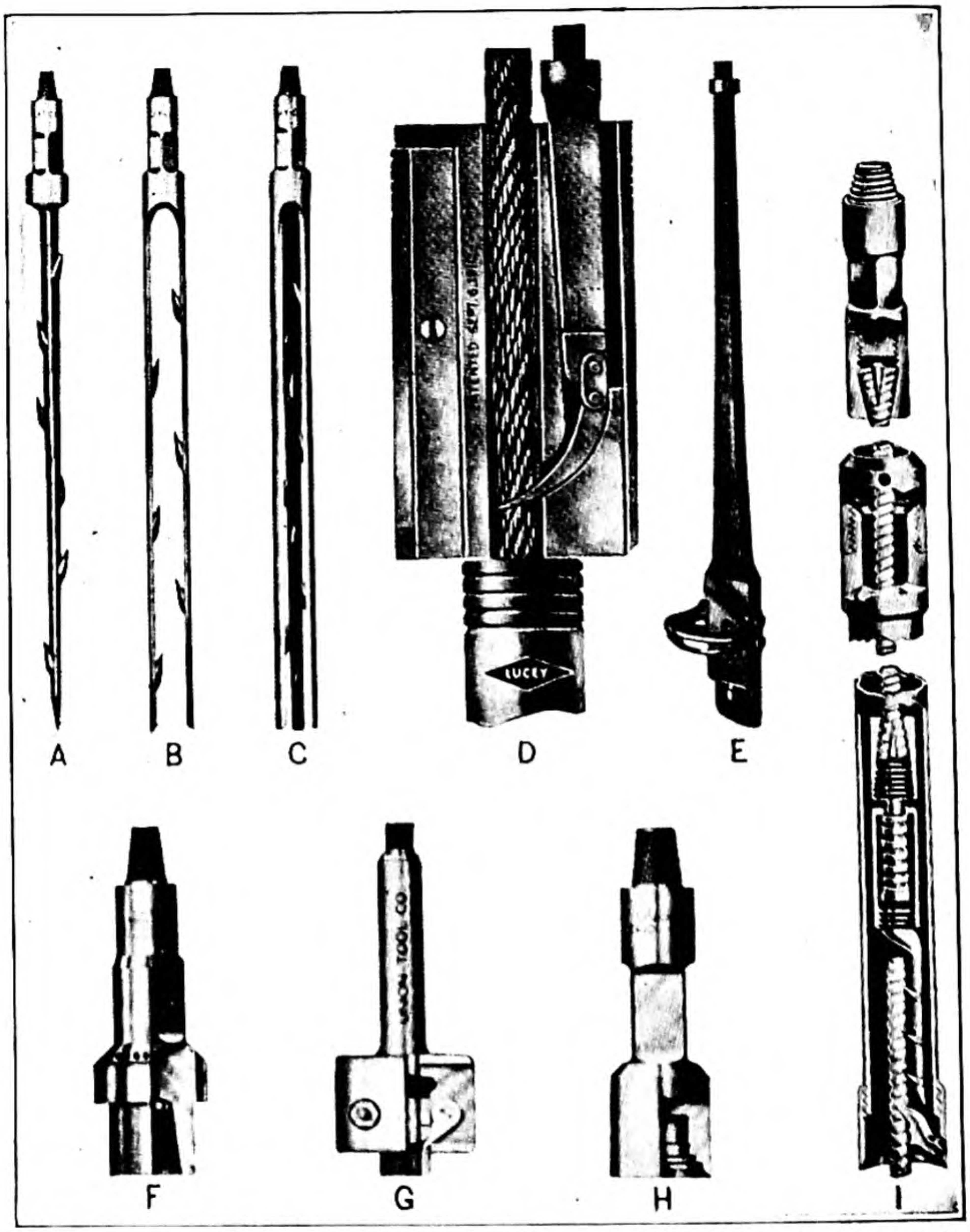


FIG. 224.—Tools for recovering drilling cable and sand line from the well. *A*, rope spear; *B*, rope grab, two prong; *C*, rope grab, three prong; *D*, Spang wire-rope knife; *E* and *G*, other types of rope knives; *F*, rope spear wadder; *H*, blind rope chopper; *I*, Heeter's mouse trap.

of the cable which passes through it, until tripped by contact with the rope socket or bailer. The disk-shaped knife then falls to an inclined position about the cable, and, when the tool is drawn up, the rope is sheared off. Still another type (see Fig. 224*D*) is equipped with a curved knife on a steel mandrel, which is driven into cutting position with the aid of a sinker bar and a light pair of jars lowered on the sand line.

RECOVERING PARTS OF THE STRING OF CABLE DRILLING TOOLS

Such a variety of accidents is possible in the normal operation of the cable drilling tools that many different fishing tools are necessary if the operator hopes to be equipped for any contingency that may develop. Perhaps the most common fishing job that arises with cable tools results from the unscrewing of a tool joint in the well. If the joints are not set up securely, or if the threads are defective, vibration of the tools while in operation may easily cause one of them to unscrew. Furthermore, unless the driller is skillful in recognizing the difference in the cable vibration after such an occurrence, the upper part of the string may be permitted to pound on the top of the detached portion until the ends become upset and the threads ruined. Breakage of various parts of the string of tools will result in all or a part of the string becoming detached—the drilling cable may pull out of the rope socket, the tool joints may "jump a pin" or break off as a result of unequal pressure on the bit, or excessive strain from other causes. Steel will cystallize as a result of the continued vibration and break at some weak cross section, such as the base of a pin joint or across a wrench square. Defective welds often open and pull apart. The jars sometimes break so that the two links pull apart. If the casing shoe is held too far off bottom, the upper end of the string of tools may fall to one side and get caught under the shoe. A cave of loose material from the walls may bury the tools. Under-reamer lugs frequently break or become loosened and fall to the bottom of the hole. Any one of these occurrences will necessitate interruption in normal drilling procedure while the detached part is recovered or the condition remedied.

Use of Various Sockets.—A variety of types of sockets have been designed for taking hold of the different parts of the string of cable tools, some of which are illustrated in Fig. 225. The "slip socket," the "combination socket" and the "collar socket" will pass over the end and take hold of any cylindrical object. Frequently they are equipped at the lower end with a conical bowl which serves to guide the upright end of the detached tool into the slips. A group of other tools, among them the "horn socket," the "round spud" and the "corrugated socket," serve a somewhat similar purpose but operate on a different principle. These tools are hollow and are driven down with the jars over the detached tool until a friction hold is taken. If the drilling cable has pulled out of the rope socket, a "tongue socket" may be used. This consists of a pair of slips on a mandrel which is lowered into the hole in the center of the rope socket. A "pin socket" may be used to engage the tapered threads of an exposed pin joint, if a tool joint has become unscrewed and the threads are not damaged. For taking hold of the jar reins when they pull apart in the well, several special forms of sockets equipped with slips in different positions are available; thus, there are "center jar sockets," intended to pass between and catch both reins of the broken jars; there are "jar rein sockets," designed to take hold when one broken rein is longer than the other; the "jar tongue socket" and the "side jar socket" are tools that pass over and grip the tongue of the jars. Of these different forms of sockets, the

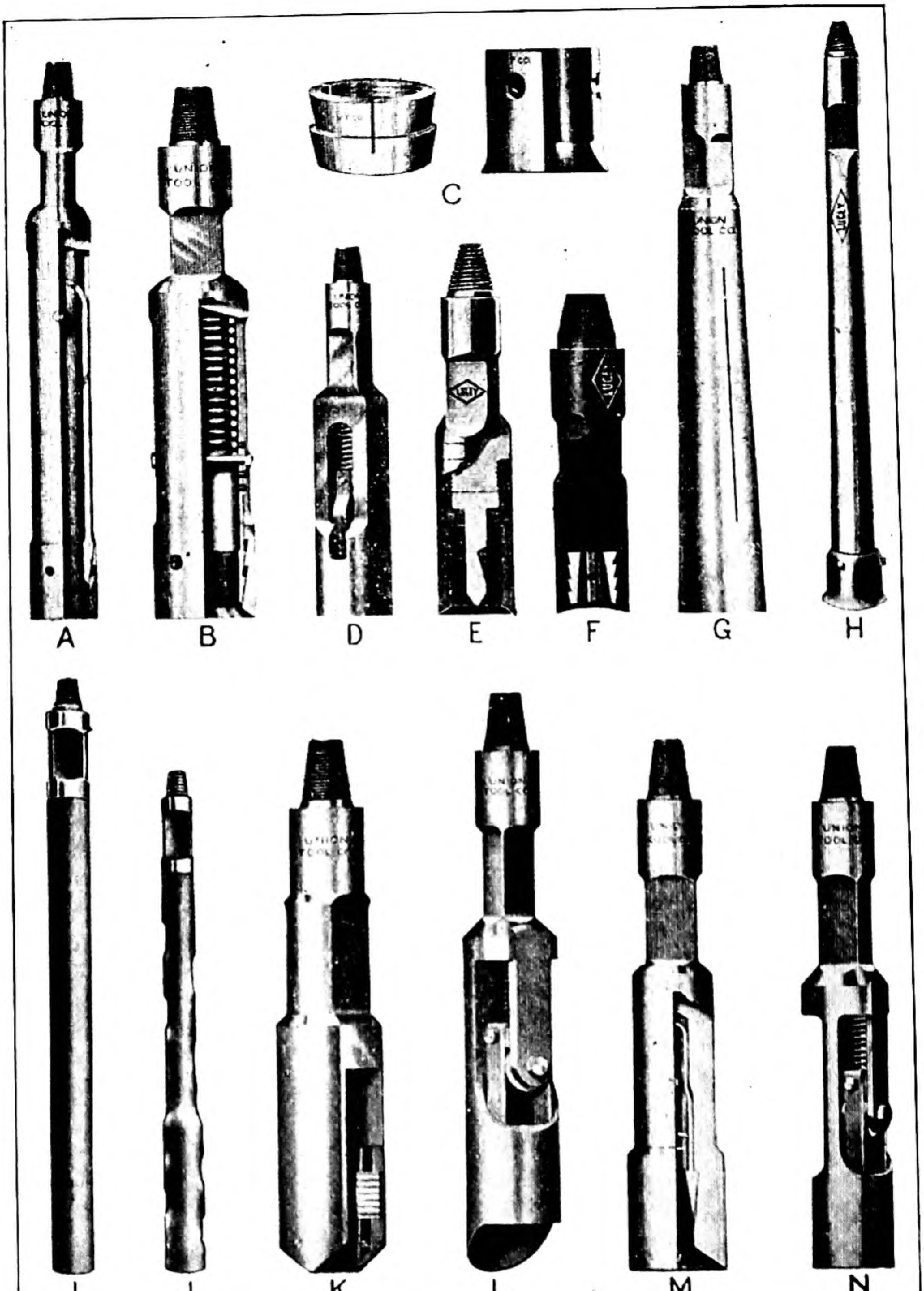


FIG. 225. Types of sockets. *A*, slip socket; *B*, combination socket; *C*, slips and bowl for combination socket; *D*, collar socket; *E*, rope socket, tongue socket; *F*, bulldog pin socket; *G*, horn socket; *H*, horn socket with bowl; *I*, round spud; *J*, corrugated friction socket; *K*, center jar socket; *L*, jar rein socket; *M*, jar tongue socket; *N*, side jar socket.

combination socket, equipped with slips actuated by the pressure of a powerful spring, is of greatest utility and is most positive and reliable in action. However, the ordinary type of slip socket, in which the slips are placed on the ends of a U-shaped stirrup, is cheaper and for many purposes equally reliable.

Use of Rasps.—If the end of the detached tool has been upset and battered by pounding of the tools, it may be necessary to remove the ragged or upset edges or corners with the aid of a rasp. This is nothing more than a large file which is suspended on a drill stem and spudded up and down about the top of the detached tool. Two forms are available: one, the so-called "side rasp," which is a single semicircular

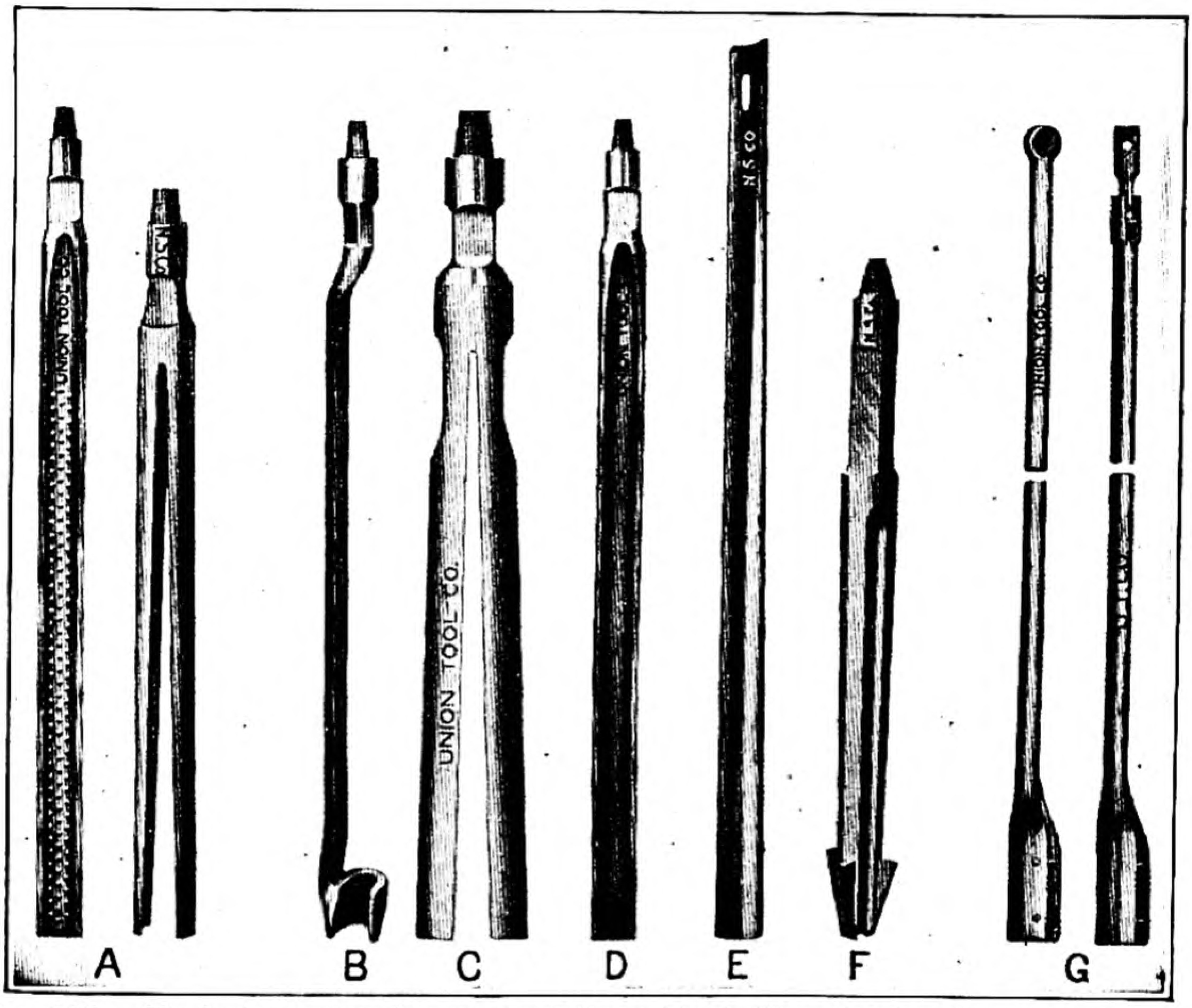


FIG. 226.—Tools for recovering parts of the cable drilling "string." *A*, types of rasps; *B*, wall hook; *C*, hollow reamer; *D*, spud; *E*, whipstock; *F*, whipstock grab; *G*, types ot jar knockers.

bar, curved to the diameter of the tool on which it is to work, and the other a "two-wing rasp," designed to pass over the end of the tool and work on two sides at once (see Fig. 226).

Use of the Twist Drill and Twist-drill Spear.—When the detached object is so large or has been so badly upset that it fills the hole and prevents operation of a rasp or other fishing tool, a hole may be drilled vertically into it with a substantial twist drill which is rotated on tubing. After the hole is drilled, a twist-drill spear may be lowered into it, a hold taken and, unless the friction is too great, the detached tool or object withdrawn. The spear used in such a small hole is necessarily weak and is not intended for lifting heavy objects or for cases which require heavy pulling.

Use of the Wall Hook or Bit Hook.—If a drilling bit becomes detached from the rest of the string in the well, it often leans against one side of the hole so that the upper

end is not accessible to fishing tools which must pass over it to operate successfully. For such a situation, the wall hook or bit hook is used. This is a tool (see Fig. 226) consisting of a long bar, offset from its point of support, with a semicircular hook on the lower end, of proper size to slip around the tool under the collar, straightening it in the hole and supporting it while it is being withdrawn. It is equipped with a pin joint at the top and can be lowered on a string of sucker rods or tubing, and functions when turned in the hole after reaching the proper depth.

Loosening Stuck Tools.—If the tools become fast in the hole as a result of caving of the walls, or of heaving of sand from the bottom, it is generally necessary to remove or loosen the material over and about them before they can be withdrawn. For this purpose, either a hollow reamer, a "spud" or a "whipstock" may be used (see Fig. 226). The hollow reamer is merely a cylindrical tube split into two wings and dressed to a sharpened edge at the bottom, which is spudded up and down on the tools in the well. The two wings spring apart after passing the casing shoe, and the inner diameter is such that the reamer passes over the detached tools in the well and works on the material about them. The semicylindrical spud is used for a similar purpose. The whipstock is lowered on top of a lost string of tools when it is desired to drill by them. The beveled face of the whipstock deflects the working tools a little to one side of the detached string. Tools may be sidetracked in this way, or they may be caused to fall into a hole drilled below them, in the hope that they will assume a more accessible position than they formerly occupied. The "whipstock grab" is a fishing tool that is used in removing the whipstock from the well after the work is completed.

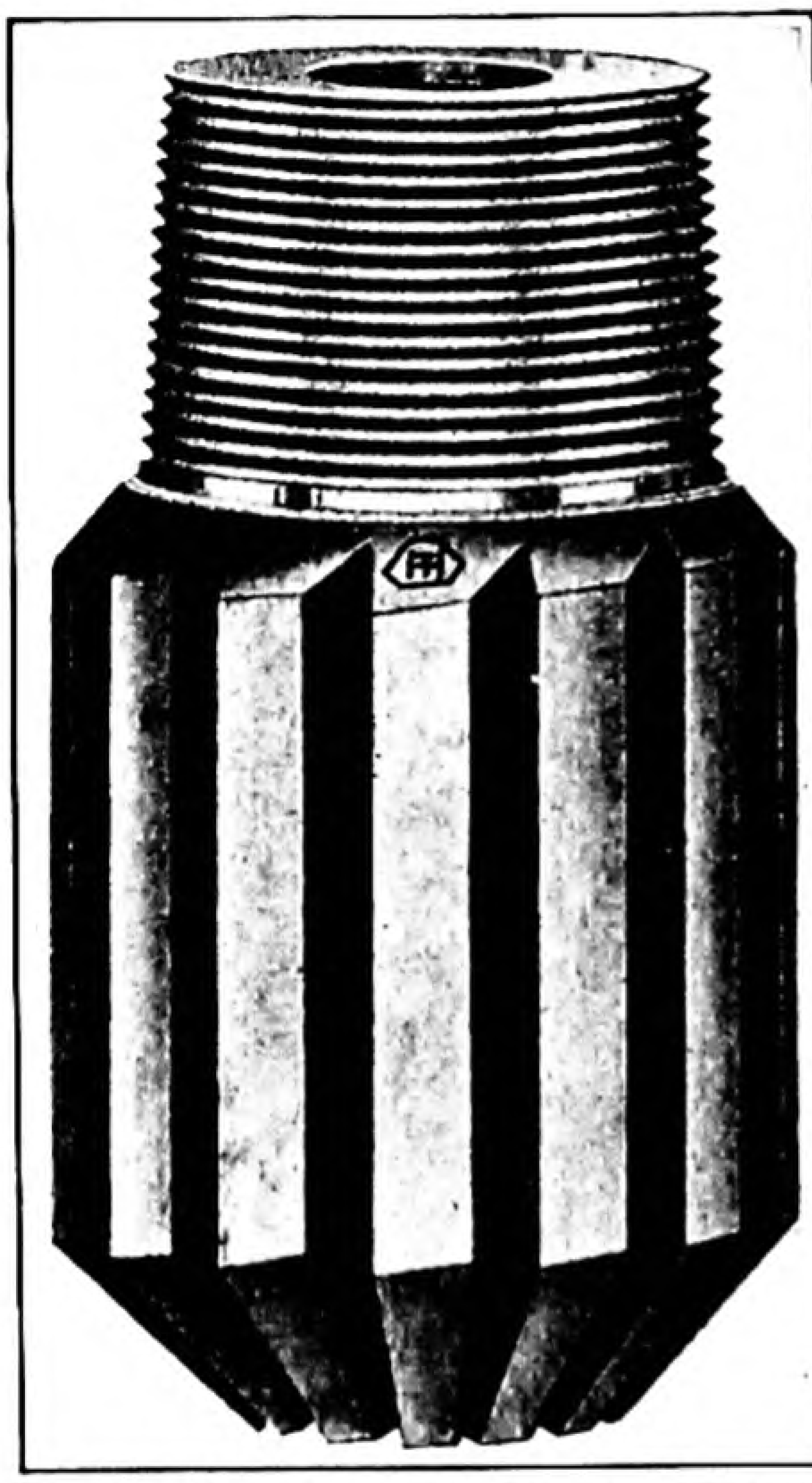


FIG. 227.—Hughes' milling tool for cutting through and sidetracking casing.

If the drilling tools are lowered without a pair of jars in the string and become embedded in the hole, it may be impossible to release them by a direct pull on the drilling cable. In such a case a "jar knocker" (see Fig. 226) is often called into service. This is a heavy bar, from 8 to 24 ft. long, which is lowered into the well on the sand line with its lower end encircling the drilling cable. The drilling cable is put under tension and the jar knocker is repeatedly raised 20 or 30 ft. and dropped on the rope socket until the combined jar and pull releases the tools. The jar knocker may also be applied in releasing the links of the jars, if for any reason they should become locked while the tools are in the well.

Use of Milling Tools.—When a pin is broken from a tool in the well, it is occasionally necessary to cut a new pin on the broken end to aid in its removal. A milling tool designed for this purpose is lowered on 2-in. tubing and revolved until the new pin is formed. A milling wheel is attached to the tubing and revolved by a rope drive from the bull wheels. A part of the weight of the tubing is sustained by a special milling jack which permits of rotation of the tubing and close adjustment of the rate of feed. Milling tools of somewhat different design are also available for cutting through casing (see Fig. 227).

RECOVERING A DETACHED BAILER

Although no very great strain is ordinarily placed upon the bailer or its supporting cable, the sand line, it will occasionally become fast in the hole so that it cannot be removed without breaking the sand line. Caving of the walls or heaving sand from the bottom may bury the bailer completely so that it cannot be withdrawn. Again, the sand line may break as a result of wear, or it may become unfastened from the bailer

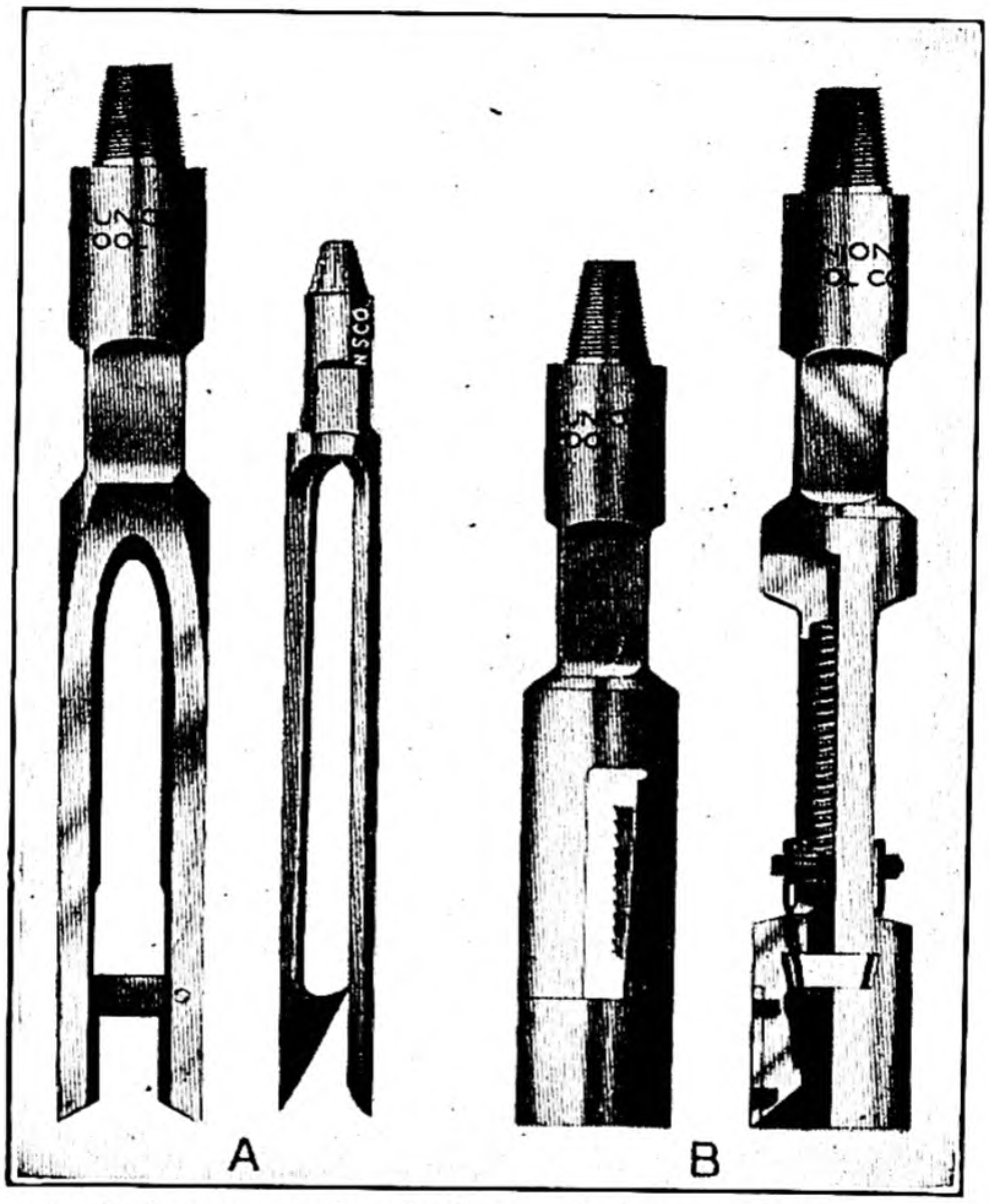


FIG. 228.—Fishing tools for recovering bailers. *A*, boot or latch jack; *B*, bailer grabs.

bail, or the bail may pull out from the top of the bailer. In such accidents one or another of the tools described in connection with casing fishing jobs or cable-tool fishing jobs may be called upon, or a special tool called a "boot jack," or "latch jack," may be of service.

If the bailer cannot be pulled and the sand line is still intact and securely attached to it, a rope knife should be lowered and the line cut at the bail. The latch jack (see Fig. 228) may then be lowered on a fishing string with long-stroke jars, a stem and a rope socket, on the drilling cable. The latch jack is a fork-shaped tool, often made from the upper

half of an old set of jars, with a small bar or latch pivoted on a pin set in one of the two reins. As this instrument is lowered, the two reins pass, one on either side of the bailer bail, lifting up the latch on its pivot. When the bail passes the latch, the latter falls back into horizontal position and later engages the bail when drawn up. The tool is substantial enough to stand heavy pulling and the jars provide a powerful upward blow which soon loosens the bailer if the bail does not pull out. In the latter event, a casing spear or a bell socket may be called into service. A tool designed especially for recovering detached bailers is called a "bailer grab" (see Fig. 228). It contains one or two slips actuated by a powerful spring and passes over the outside of the cylindrical portion of the bailer. If all of the methods suggested above fail, the bailer may be drilled up with the tools and sidetracked.

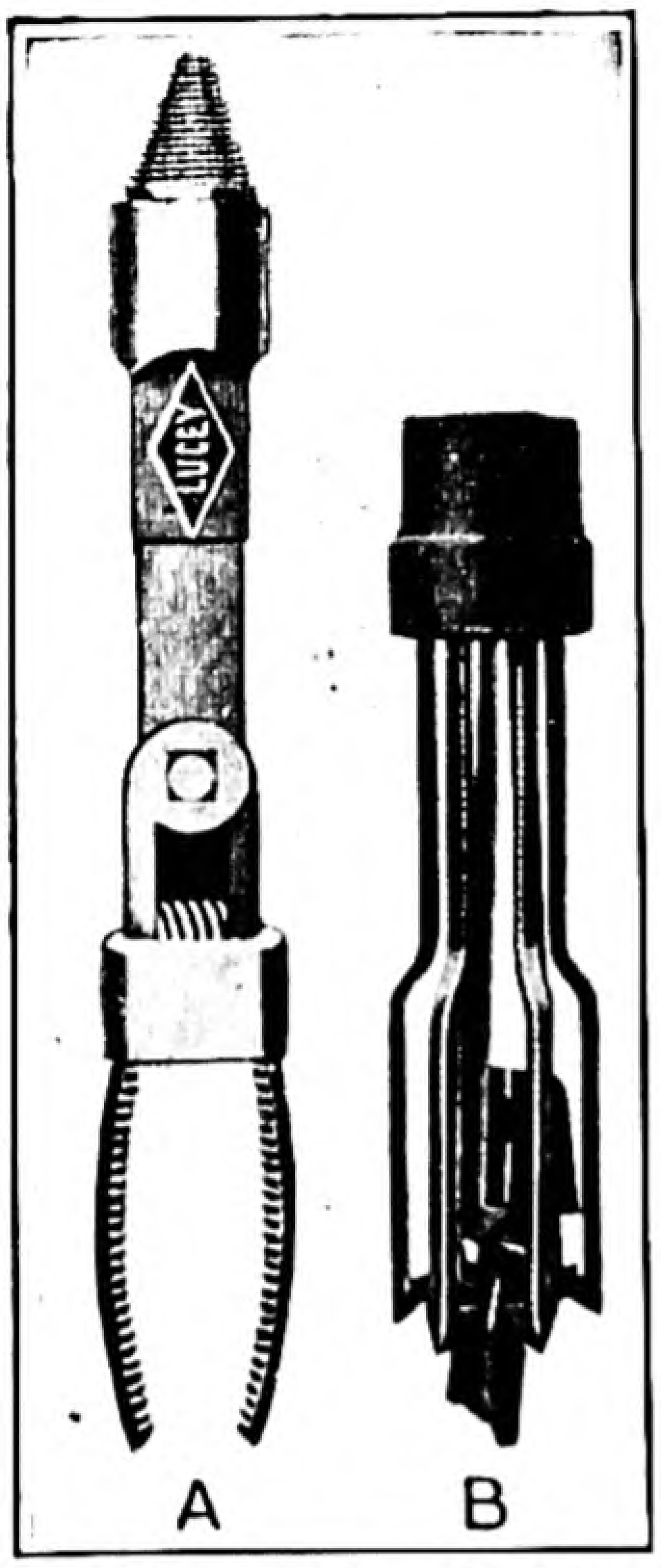


Fig. 229.—Fishing tools for recovering small irregularly shaped objects. *A*, alligator grab; *B*, devil's pitchfork.

RECOVERING SMALL IRREGULARLY SHAPED OBJECTS

Recovery of small irregularly shaped objects, such as under-reamer lugs, slips or parts of fishing tools that break in service, is accomplished with the aid of either an "alligator grab" or a "devil's pitchfork." The manner in which these tools operate will be apparent from an inspection of the illustrations given in Fig. 229.

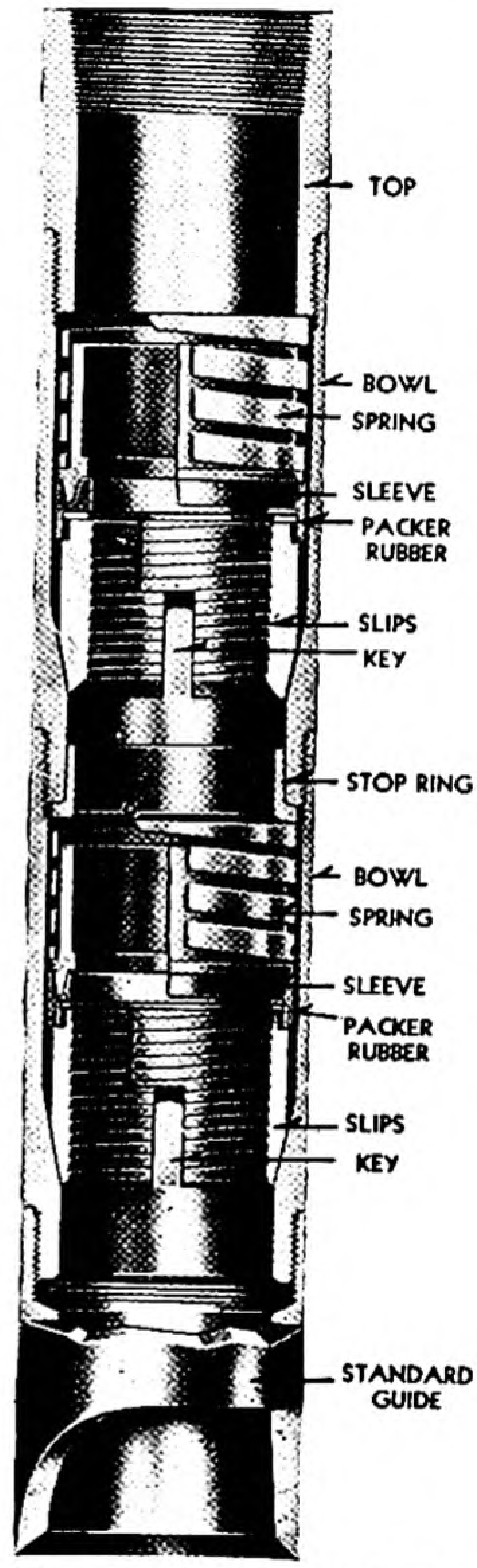
Electromagnetic Fishing Tools

Electromagnets have been employed in recovering small or relatively light steel objects from wells, and some models, recently perfected, are sufficiently powerful to lift heavy drilling tools. In order that it may develop maximum lifting force and not stick to the casing as it is withdrawn, a successful electromagnetic fishing tool must be so designed as to concentrate the magnetic force entirely on the lower end where it makes contact with the object to be retrieved. It is lowered into the well on a steel cable the core of which carries insulated wires through which the current necessary in the operation of the magnet is conducted. A service truck used in conjunction with the tool carries a hoisting drum on which the special conducting cable is reeled and a motor-generator set which furnishes direct current of suitable voltage for operation of the magnet. An electromagnetic fishing outfit of this type used in the California and

Texas oil fields is capable of lifting loads of 1,000 lb. or more and yet may be operated through 8¼-in. casing. Such a tool is quicker and more universal in its application than others which depend upon accurately gauged slips and which often fail to work because the detached tool is in an inaccessible position.

RECOVERING FRACTURED ROTARY DRILL STEM

The most frequent type of fishing job in rotary drilling is that occasioned by the twisting off of the drill stem. Such a fracture usually occurs near the lower end of the stem. The fracture may consist of a simple shearing of the pipe, or failure may occur at a tool joint. In some cases the back lash of the upper portion of the column of pipe, after the stem breaks, will cause a second fracture at some point above the first so that the pipe is in three pieces in the well.



(Courtesy of American Iron and Machine Works Co.)

FIG. 230.—Double-bowl type of releasing and circulating overshot.

The overshot (see Fig. 230) is the favorite tool for recovering drill stem twisted off in this way; but if mud has settled about the stem, it may be necessary to use a "wash-down spear," which is a special form of trip casing spear equipped with a diamond-pointed bit on the lower end and with openings through it for passage of the circulating fluid. It is lowered on a column of drill pipe of the same size as that detached in the well. The diamond bit, aided by the pump circulation, quickly forces its way through the accumulated mud and enters the broken stem until the slips take hold, after which the pipe can usually be withdrawn.

If the detached section of drill pipe cannot be pulled, the spear can sometimes be recovered by rotating the drill pipe on which it is lowered. Or, if the fishing string has been tightly made up, some of the lost pipe may be unscrewed by backing up or turning the fishing string at the surface in the hope of unscrewing one of the tool joints in the detached column of pipe.

In many fishing operations, as in recovering a section of rotary drill pipe after a twist-off, it will be somewhat uncertain whether or not the "fish" has been engaged by the tool used. In such cases, it is often convenient to use a weight indicator on the hoisting line (see page 315). This device makes it possible for the driller to detect the slight difference in weight of the fishing string after the tool has taken hold.

Often mud and drill cuttings settle about the parted section of pipe so that it cannot readily be withdrawn after the overshot has taken hold. The lip of the overshot may be pointed to assist in "washing down" over pipe buried in sediment. The Baash-Ross overshot is equipped with a packing ring which, on lifting the fishing

string after the tool has taken hold below a tool joint or coupling, closes the annular space between the fishing string and the parted drill pipe or casing. Circulation may then be established down through, and up and about the outside of the parted pipe, thus assisting in freeing it from the accumulated detrital material.

If the parted drill stem cannot be recovered with either the overshot or the wash-down spear, it may be possible to unscrew a part of it in the well and remove it in sections. For this purpose, a string of pipe equipped with left-hand threads is made up, and a hold taken on the detached pipe, either with a spear or with a left-hand-threaded pipe tap or die nipple. The fishing string is then rotated counterclockwise, which tightens the left-hand threads but unscrews the right-hand threads of the detached stem. There is more or less uncertainty as to just where the detached column will unscrew, but three or four joints of pipe can often be recovered with each run.

The Houston Engineers' reversing tool may be conveniently used in connection with left-hand taps or dies in backing off parted casing or drill pipe which cannot be pulled from the hole. This device, connected in a string of right-hand drill pipe or tubing, imparts a left-hand motion to the tap or die. When the tool has taken hold, the parted section of pipe is unscrewed at some collar or tool joint below, after which it is possible to remove the portion above the uncoupled joint.

For cutting off frozen drill pipe, it is necessary to use a cutting tool that operates from the outside rather than the inside. The Baash-Ross drill-pipe cutter is of this type. It is lowered to the desired point on a string of pipe that telescopes over the column of parted drill pipe. On lifting the tool, an overshot takes hold below a collar or tool joint. Strain is then taken and the fishing string rotated, which forces the cutters against the drill pipe. After the pipe has been severed, that portion above the overshot is withdrawn with the fishing string.

When rotary tools are in use, the ordinary telescoping, link type of fishing jars may be unsuitable. In this case, the Kammerdiner rotary jar may be used. This tool is connected in the fishing string near the lower end. When the fishing tool has taken hold, the drill pipe or tubing on which it is lowered is turned one full turn to the left and then to the right three turns, when a threaded section of the tool is disengaged, causing the fishing string to be jerked upward under the tension provided, thus delivering a powerful upward jerk to the "fish."

When a section of detached drill pipe or casing or tool has fallen over to one side of the axis of the well, or into a cavity which may have formed about the well as a result of a cave, special forms of wall hooks or "knuckles" may be used in conjunction with other appropriate fishing tools. One variety of tool of this class, manufactured by the Specialty Oil Tool Company, designed for use with rotary tools, is deflected from the axis of the well to one side at the will of the operator by application of hydraulic pressure developed through the drill pipe. On rotating slowly, the tool engages the lost pipe or tool and draws it back into the axis of the well. The Soteo hydraulic wall hook is also equipped with slips which grip casing or drill pipe after it has been straightened in the hole so that it may be lifted to the surface with the fishing string. Special types of eccentric sockets and grabs are also available for off-center fishing operations.

If the lost drill pipe cannot be recovered by either of the methods suggested above, a whipstock is lowered into the hole and the parted section is sidetracked. If the upper end of the detached stem happens to be up inside the well casing, a hole may be cut through the casing for the passage of the drilling bit and stem with the aid of a milling tool, after the whipstock is in position.

A means of attaching the drill collar and rotary bit to the drill stem in such a way that they are not detached from the stem if a twist-off occurs near the lower end is

said to reduce greatly the number of rotary fishing jobs. The Baughner device, named after the inventor, J. D. Baughner, a California well driller, ties the four bottom joints of drill stem, the drill collar and bit to the nearest tool joint above. This is accomplished by means of a wire cable 80 ft. long, babbitted into a rope socket at each end, the sockets being shouldered and resting on the pin of the drill collar at the lower end and at the upper end on the pin of the tool joint. Between the rope sockets and the pins are placed slotted washers, which permit passage of the circulating fluid. The cable rotates with the stem and restricts circulation of the mud fluid but little. Should the drill collar or either of the lower joints break, the rope keeps them suspended so that they can be withdrawn with the upper part of the drill stem. On one well drilled in California this device prevented 24 out of 27 fishing jobs due to twist-offs.

USE OF ACIDS IN FISHING OPERATIONS

Occasionally, in difficult fishing jobs near the bottom of the hole, resort may be had to the use of acids capable of dissolving the metal or the tools or the minerals composing the wall rocks or detrital material settled about the lost tool or pipe. The appropriate acid to use will depend upon the conditions presented and the objective to be gained, but hydrochloric, nitric, sulphuric and hydrofluoric acids comprise the list from which a choice must ordinarily be made. Limestones are easily soluble in hydrochloric acid, silicates in hydrofluoric acid. Nitric acid and sulphuric acid, in certain concentrations, are effective in dissolving iron and steel. Although the lost tool will not ordinarily be entirely dissolved by acid treatment, it may be so reduced in size that it can be more readily freed from the walls of the well. The acid, brought to the well in carboys, is lowered to bottom in a dump bailer (see page 482).

DETERMINING THE POSITION AND CONDITION OF A DETACHED TOOL IN THE WELL

Before selecting a fishing tool to recover a detached tool in the well, it is often essential to determine its position in the hole as well as the condition, form and exact size of the upper end. For this purpose, an "impression block" is prepared. This consists of a round piece of wood about 2 ft. long, which is of such diameter that it can be readily lowered through the hole, and concave at the lower end. A few nails projecting from the concave end serve to hold a mass of soft soap. The impression block is lowered into the hole, either on the bottom of the bailer or attached to the lower link of the jars by a pin joint cut on its upper end, until it rests upon the top of the detached tool. When withdrawn, the indentations in the soap indicate fairly well the position, form and size of the upper end of the tool in the well and enable the driller to select a fishing tool to recover it.

It has been suggested that a special camera might be devised, with an electric lighting device and electric control, which could be lowered into the well to make a photograph of parted casing, a detached tool

or any other obstruction. Such cameras are used in photographing the position of magnetic needles in making surveys of wells but seem scarcely applicable under the conditions pertaining in fishing operations. The well fluid and accumulated sediment would generally obscure the object even if a workable camera could be devised.

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CHAPTER XIV

WELL-COMPLETION METHODS

On encountering an oil or gas stratum which gives evidence of being commercially productive, the driller proceeds carefully and cautiously. Perhaps the stratum is under high pressure, and unless precautions are taken there is danger of a blowout which may be accompanied by an uncontrollable flow of oil and gas. Reduction of the specific gravity of the mud-laden fluid by contamination with occluded oil and gas will sometimes be responsible for a blowout in rotary drilling. Such an event usually results in great loss of oil and gas and often seriously damages the well and its equipment. If the producing stratum is an unconsolidated sand, the well may "drill itself in" as soon as the cap rock is penetrated, large quantities of sand flowing to the surface with the oil and gas and forming a cavity in the oil sand about the well.

If the oil sand is under low pressure, there may be very little evidence of the presence of oil during the ordinary processes of drilling. A high fluid level within the well may prevent any oil or gas from escaping from the sand. If the rotary method of drilling is employed, the sand faces soon become mudded so that their true character is obscured. The circulating fluid may so thoroughly wash the drill cuttings that little evidence of the presence of oil remains. To the trained eye of the driller, however, there will usually be evidence that at least leads him to suspect the presence of oil. Perhaps a little oil sand clinging to the drilling bit or the bailer, or a few globules of oil or gas froth on the mud ditch, will tell the story. If there is evidence of oil and the rotary equipment is in use, the clay content of the circulating fluid should be at once reduced by adding water to the fluid in the mud pit. A core of the material in the bottom, taken with a suitable core barrel, will give positive evidence. If the cable tools are used, the bailer will usually bring up samples of the material in the bottom that have not been greatly disturbed. A chloroform test will be decisive if there is any doubt of the presence of oil.

Although we may depend upon such indications and tests for qualitative evidence, it is often difficult to form any reliable estimate of the productivity of the well without making an actual production test. The well is "bailed down" to remove the hydrostatic head on the oil stratum and allow the oil and gas to escape from the sand. This is done cautiously

in order to avoid a sudden flow which might be difficult to control. As the hydrostatic head is gradually reduced by continued bailing, oil will begin to enter as soon as the balance of pressure is in its favor and will float to the top of the fluid in the well, increasing in quantity as the head is reduced. If the productive sand is unconsolidated, it may tend to heave or flow into the well with the oil, occasionally filling the hole for hundreds of feet above bottom and necessitating prolonged bailing or even redrilling. If there seems to be danger of this, care should be taken not to bail the well down too rapidly or too far, and the bailer should be lowered to bottom for its load in order to observe the tendency of the sand to enter.

In the case of reservoir rocks of limestone or "tight" sands or shales, it is often necessary to make an actual pumping test for a few days before the full productivity may be realized. In hard, close-grained rocks, such as the limestones, it is also customary to "shoot" the wells with the purpose of fracturing the oil stratum so that oil may freely enter. Rush of gas from the well as a result of a shot of nitroglycerin or dynamite often causes a flow of oil which may last for several days or weeks, though the well may have given little evidence of the presence of oil prior to shooting.

It will be noted that the manner in which oil makes its presence known as the drill enters the oil stratum varies markedly, depending upon the nature of the reservoir rock and the pressure under which it is stored. The method of drilling employed also has its influence in determining in some measure the hydrostatic head resisting entrance of the oil. In high-pressure territory there will be no uncertainty, and flowing wells or gushers, in which the oil is thrown from the well mouth high into the air, occasionally offer problems in control of exceedingly destructive forces. In the case of low-pressure strata or close-grained rocks, on the other hand, the skill and ingenuity of the driller may be taxed to the utmost to establish conditions within the well which will cause it to yield oil in commercial amounts.

Drilling should be continued until the oil stratum is penetrated and, unless bottom water is encountered immediately below, the hole should be drilled for an additional 10 or 20 ft. This serves as a sump for the accumulation of sediment or cavings from the walls, or for sand which may enter with the oil, and also as a reservoir in which oil may accumulate. It is important that sand entering with the oil should not accumulate within the well opposite the producing strata since it reduces the rate of production.

If the walls are firm and do not tend to cave, the well may be completed without casing of any sort opposite the productive horizon. This practice is characteristic in most of the fields of the Eastern United States.

The last string of casing or the "oil string," so named because it is the only one in contact with the oil, is in this case carried to a point immediately above the oil stratum and set on a firm shoulder of rock in such a way as to exclude water and cavings from above.

If the productive formation is a loosely cemented sand or sandstone, as is generally the case in the fields of California, Louisiana and southern Texas, it is necessary to carry the oil string through the oil sand to the bottom of the well; and in order that the oil may gain admittance to the pumping device which is placed within the casing, the pipe is perforated opposite the oil sand with numerous round holes or slots. These openings are frequently equipped with screens of various types which allow the oil to pass but exclude the sand which tends to flow in with the oil. The lower end of the oil string is near bottom and should be securely plugged to prevent water or heaving sand from entering from below.

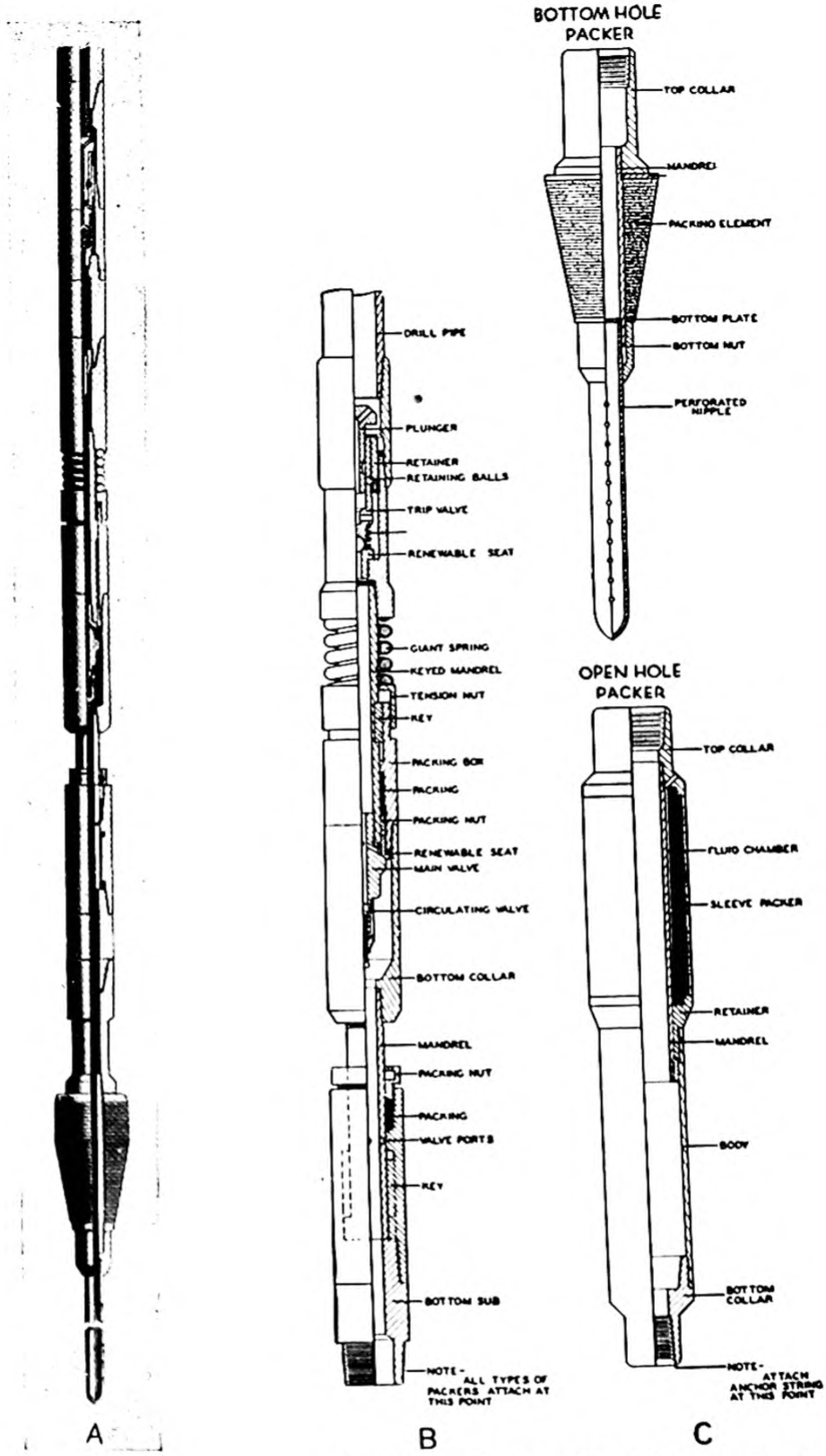
FORMATION TESTERS

Special tools called "formation testers" are available for securing a sample of the fluid yielded by a given formational interval penetrated by a well, without cementing casing and without bailing the drilling fluid from the well. The formation tester is also helpful in testing the effectiveness of water shutoffs and may be used to determine whether or not casing perforations are capable of admitting fluids freely to the well.

The formation tester utilizes a packer which, when properly seated against the wall of the well or casing, relieves the test interval immediately below of the hydrostatic pressure of the overlying column of drilling fluid in the well. Fluid is thus permitted to flow from the formation, through the tester, into the drill pipe against pressure but little above atmospheric. Fluid entering the drill pipe is trapped by a system of valves in the tester, so that it may be withdrawn from the well with the drill pipe for subsequent examination; or, if the formation pressure is sufficient to cause flow to the surface, a sustained flow test through the drill pipe will provide a quantitative measure of the productive capacity of the interval tested.[36]

The Johnston Oil Field Service Corporation, pioneers in the development of formation testers, offers tools of several different types: one designed for use inside of casing, and others for use in open hole. They differ chiefly in the design of the packer. Probably the most dependable type is one designed for use in a "rat hole" of reduced diameter drilled in the bottom of a well (see Fig. 231), under conditions where it is desired to determine the character of fluid yielded by, and productive capacity of, a potential oil- or gas-producing horizon before deciding whether or not commercial production may be obtained from it. After penetrating the cap rock, the regular drilling tools are withdrawn and a smaller hole is drilled with special tools including a reamer that forms a conical seat for the packer.

In addition to the packer which, when seated on its conical shoulder on the wall of the well, isolates the test interval below, the tool comprises a series of valves each



(*Courtesy of Johnston Oil Field Service Corp.*)

FIG. 231.—Formation tester. *A*, assembled tester on drill pipe in position for test; *B*, sectional view of tester, showing structural detail; *C*, above, bottom-hole packer; below, open-hole packer.

having a different function. These are assembled as a unit and connected to the bottom of the drill pipe. As the packer is pressed against its shoulder, the powerful spring is compressed, opening the retaining valve. This valve cannot open, however, until the trip valve is opened by a short steel bar go-devil dropped upon it from the surface through the drill pipe. Fluid may now enter the tester from the test interval through the perforated anchor or tail pipe, and rise into the drill pipe above. Fluid rises until equilibrium of pressure with that of the fluid in the formation is attained. It may reach the surface and continue to flow if the formation pressure is sufficiently high.[34]

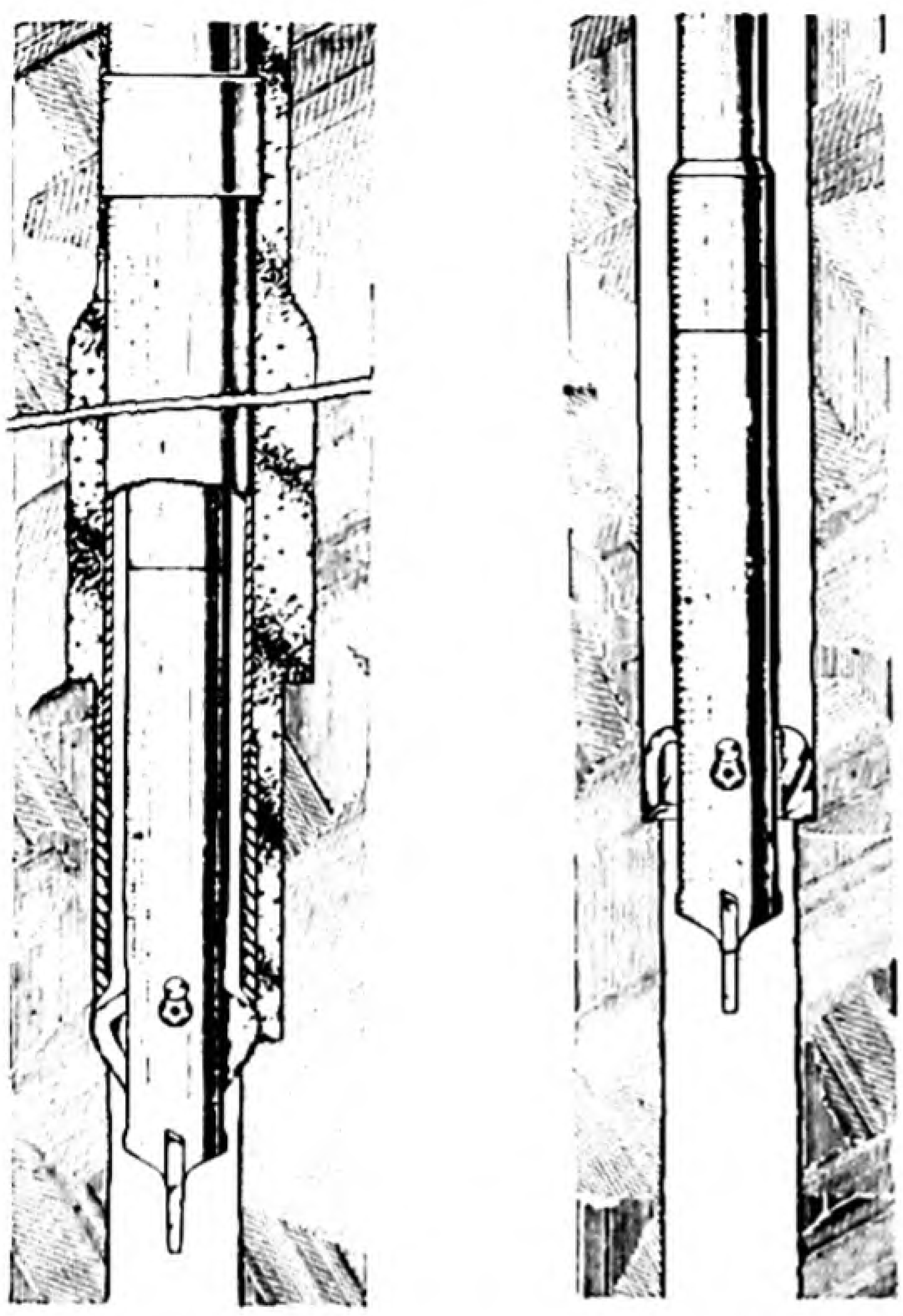
As fluid rises in the drill pipe, air will flow from the open pipe at the surface and the rate at which fluid is rising above the tester may be estimated by noting the rate of air displacement. When and if equilibrium is attained, the drill pipe is lifted, opening the circulating valve, which allows drilling fluid to enter the test section and equalize the pressure above and below the packer. As the weight is relieved, the compression spring expands and closes the retaining valve, thus imprisoning the fluid that has passed through the tester into the drill pipe. As the drill pipe is uncoupled at the surface, this fluid can be identified and sampled for further testing. Thus, we may find a part of the drill-pipe column (a certain number of stands) filled with gas, part with oil, part with saline water from the formation and part with drilling fluid. The proportions of each provide a basis for estimating the productive capacity of the well.

Bottom-hole Pressure Indicators.—Although it is possible to estimate the formation pressure by noting the height to which fluid rises above the formation tester in the drill pipe, a more dependable record is secured by connecting a pressure-recording device below the perforated anchor of the formation tester. Any of the several types of depth-pressure recording instruments described in the companion volume of this work (see "Oil Field Exploitation," pages 148–152) may be employed for this purpose. A record drawn by a stylus on a chart contained within the instrument, available when the tester is withdrawn to the surface, indicates the pressure at all depths while the instrument is being lowered and raised through the well, and the variation in pressure throughout the period of the formation test. The maximum pressure reached at the end of the test will be of particular interest as a measure of the static pressure within the formation yielding fluid to the test interval.

WALL-SCRAPING WELLS THROUGH THE PRODUCING INTERVAL TO REMOVE THE CLAY SHEATH AND ENLARGE THE HOLE DIAMETER

When a well is drilled by the rotary method with a clay-laden water-base drilling fluid, the producing formation exposed in the wall of the well is left coated with a sheath of deposited clay. Clay penetrates the pore spaces of the wall rocks to some extent; thus the surface sheath is "rooted" in the formation and may not easily be removed. In high-pressure formations, the clay will be forced out of the pore spaces and dislodged from the wall surfaces by rapid flow of oil and gas into the well when it is brought into production; but in low-pressure formations the clay may be removed only imperfectly, so that the well never attains its full potential production. With the purpose of removing this clay sheath, the walls of the well may be mechanically scraped before placing the liner or screen pipe, the scrapings being circulated to the surface in a thin

circulating fluid incapable of redepositing an adherent wall sheath. Continued application of the scraping tool may result in a considerable enlargement of the diameter of the well through the producing horizon, thus affording space for a "gravel pack" about the liner and otherwise promoting production efficiency by reducing formation resistance to flow of fluids into the well. Tools known as "wall scrapers" and "wall scratchers" are widely used for this purpose.



(*Courtesy of Baker Oil Tools, Inc.*)

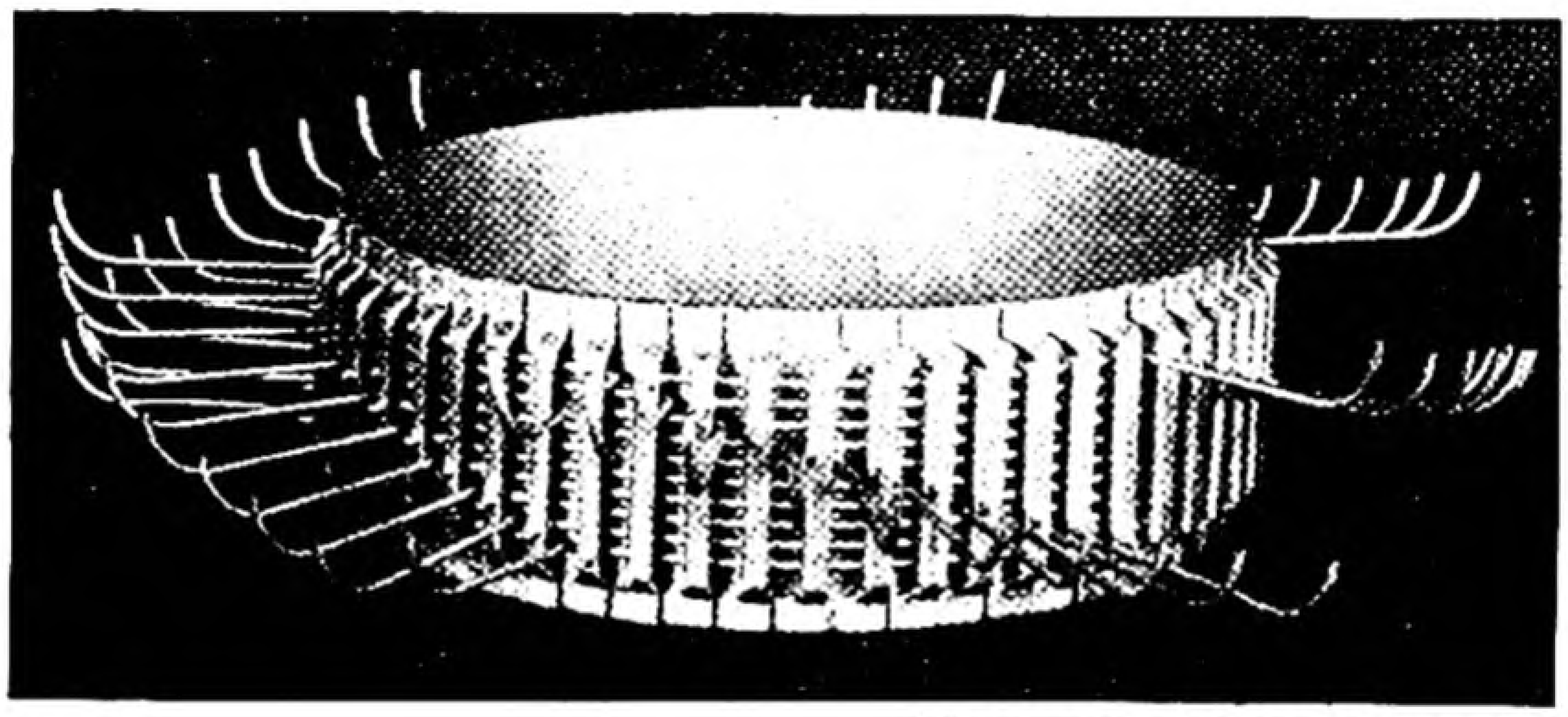
FIG. 232.—Hydraulically actuated wall scraper. *A*, blades expanding under influence of hydraulic pressure as tool is rotated; *B*, blades fully expanded, in position for reaming hole.

The Baker Wall Scraper.—This sturdy tool consists of an alloy steel body, containing a piston to which are connected two cutting blades mounted in such a way that the blades fold into the body of the tool while running in and out of the hole (see Fig. 232). When lowered to the point where it is to be applied, on the lower end of a column of drill pipe, the piston is forced downward by application of pump pressure, thus expanding the blades outward and upward against the wall of the well. The tool is then rotated with the drill column. The blades, cutting their way to a fully expanded position, are held in this cutting position by the shoulder thus cut on the wall of the well. If the formation is soft, the blades are held in their expanded position by the pump pressure. Circulation passageways direct the circulating fluid upon each blade, lubricating and cooling the cutting surfaces and carrying the cuttings up and away from the blades. After the blades are fully expanded so that the cutting edges are in a horizontal position, the drill column is slowly lowered as the wall is cut away. A pilot bit below the scrapers projects into the small hole ahead of the blades and keeps the enlarged hole concentric with the original hole. A considerable enlargement of the hole is possible by use of this device. For example, a scraper that operates through $9\frac{5}{8}$-in. casing is capable of enlarging the hole in $\frac{1}{4}$-in. steps to a diameter as large as 19 in.

Wall-cleaning Guides.—A device sometimes called a "wall scratcher" is also helpful in removing the mud cake on the wall of the well through the reservoir sand before landing perforated or screen pipe. This is in the form of a steel collar, spot-welded to the exterior of the casing, to which are attached rows of tempered spring steel wires bent at the ends so that they present sharp points against the wall of the well when the casing is raised (see Fig. 233). The outside diameter of the wire assembly is slightly greater than the hole diameter, so that the wires bear firmly against the wall of the well. Mounted at intervals along a column of screen pipe, slotted pipe, or gravel-packed liner, the pipe is lowered to its position in the well and then raised and lowered repeatedly through an interval sufficient to bring the wire points in contact with all parts of the wall of the well.

Meanwhile, water or oil is pumped down through a wash pipe and under the shoe of the liner, to circulate clay scraped from the walls up through the annular space to the surface. The wire guides serve not only to remove deposited clay from the wall of the well, but also to keep the pipe centered in the well. This device is also helpful in cleaning the walls of a well and centering the casing in the hole prior to a cementing operation (see page 480).

Removal of Mud Sheath and Interstitial Clay from the Walls of Wells by Acid Treatment.—Some types of clay, particularly the bentonitic varieties, are dissolved or disintegrated to a considerable degree by application of strong acids. "Mud acid" has a base of hydrochloric acid to which are added surface-tension-reducing and wetting agents and other chemicals that prevent formation of emulsions and inhibit solution of iron and steel. The product serviced to the industry by Dowell, Inc., will dissolve 1/3 lb. of typical bentonitic clay per gallon.



(Courtesy of B. & W., Inc.)

FIG. 233.—Wall-cleaning guide.

A charge of 1,000 gal. of this acid, applied to 10 or 15 ft. of the wall of a well where it penetrates a producing formation, will dissolve a large part of the clay sheath formed in drilling and disintegrate the remainder so that it falls to the bottom of the well or may readily be washed free of the walls by circulating water or oil. Jetted through the perforations of a liner or screen pipe, it also removes clay that has become lodged in the perforations or screen openings. Many reservoir sands contain some interstitial clay and, because of its low surface tension and highly developed wetting properties, mud acid is capable of penetrating for some distance into the strata forming the walls of wells, dissolving the finely divided clay in the pore spaces of reservoir sands and thus increasing their permeability in the critical zones immediately surrounding the wells. Treatment of wells with mud acid has produced substantial increases in initial production of wells in some fields where clay clogging of the wall rocks has been troublesome.[64]

Conditioning of Drilling Fluid to Avoid Excessive Clay Deposition and Water Absorption in Well Completion.—Proper drilling-fluid control

will obviate much of the difficulty that sometimes results from excessive deposition of clay on the walls and within the pores of wall rocks in producing formations. A highly colloidal drilling fluid of low density will quickly seal the walls with a thin sheath of clay that permits of minimum water loss. Such a clay sheath is also soft and easily removed by washing when the well is ready to produce. Care should also be taken in drilling through the producing zone to avoid excessive differential pressure that would tend to force drilling fluid into the wall rocks. Even though clay may be deposited only on the wall of the well, high loss of water to the producing formation displaces oil from rock surfaces in the vicinity of the well and renders them water wet. A "water block" thus formed may not subsequently be readily displaced, especially in low-pressure reservoir rocks. Though oil and gas may subsequently find their way through such "water dams" in the more permeable drainage channels, a large part of the rock surface exposed in the area about the well may remain water wet, thus in some degree restricting the productive capacity of the well.

Acid Treatment of Lime-bearing Drilling Mud as a Means of Removing Adherent Clay.—In anticipation of acid treatment during the process of well completion, the drilling fluid used in penetrating the reservoir rock may contain finely pulverized limestone, which is deposited with the clay sheath on the wall of the well. Later, when it is desired to remove the mud sheath, hydrochloric acid is spotted in the interval to be treated and moderate pump pressure applied. The acid dissolves the calcium carbonate of the limestone and thus disintegrates the wall sheath so that it is readily washed from the walls and circulated to the surface. Penetration of acid into the wall rocks and effervescence caused by release of carbon dioxide, due to solution of limestone, further assists in clearing the rock pores of accumulated clay.

WATER EXCLUSION IN WELL COMPLETION

Some of the most troublesome problems in well completion are encountered in excluding water from sources within or immediately adjacent to the oil-producing zone. It is here assumed that all top waters have been successfully excluded by landing and cementing a string of casing within or above the cap rock. The water sources with which we are here concerned are strata intermediate between two oil-yielding strata, edge water entering the well from the same strata that yield the oil, or bottom water from strata below but stratigraphically closely identified with the oil-yielding formation. Often the oil-producing interval penetrated by the well will include some water-yielding strata. In this case, the well will produce both oil and water, often more water than oil. Presence of water in the well not only reduces the oil-yielding

capacity, but also occasions extra expense in pumping the additional fluid to the surface and dehydrating the oil, which is often in the form of a refractory emulsion. There is every incentive to eliminate as much of this water as possible and usually, if it is more than a few per cent of the production, means are adopted for accomplishing this during the process of well completion. Several methods of doing this are available, involving cementing procedures or use of chemicals or plastics as discussed in an earlier chapter (see pages 464–476).

If the source of the water is below the oil-producing strata, one or another of the plugging methods is indicated (see page 470). If the water is edge water, plugging the lower part of the oil reservoir rock may be successful in eliminating a part of the water, though in such wells edge water will be a recurring problem as reservoir depletion progresses and the oil-water interface rises. Intermediate sources of water between oil-producing strata may be sealed by squeeze-cementing procedures (see page 524), or by cementing a liner throughout the producing interval and then gun-perforating the oil-producing horizons (see page 522).

In water exclusion accurate logging is essential, particularly of information that will indicate the depths to top and bottom of all oil-yielding and water-yielding intervals. Such information may be afforded by electrical logs (see page 630), or by use of formation testers (see page 561). Often, repeated tests followed by appropriate remedial measures will be necessary effectively to exclude the water and permit the well to produce reasonably clean oil. Only when this condition is attained will the well be capable of demonstrating its maximum productive capacity.

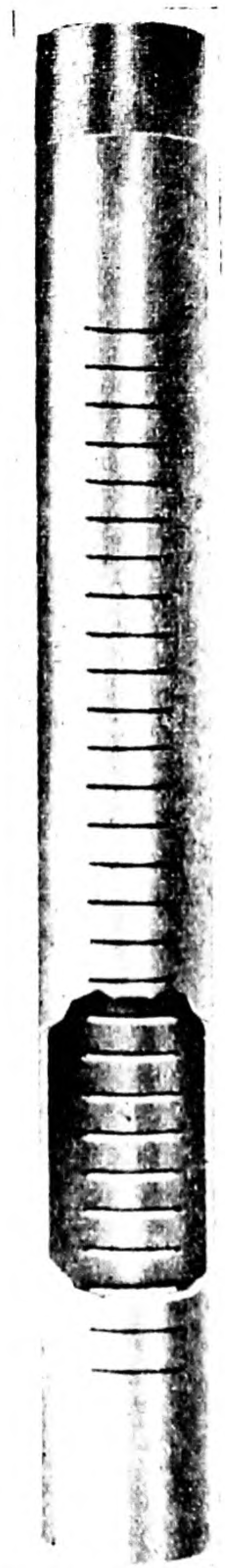
SAND EXCLUSION IN WELL COMPLETION

Often the reservoir rock is partly or loosely consolidated, so that it tends to disintegrate and flow into the well under the influence of oil and gas moving through its pore spaces. When this condition exists, the wall of the well must be supported by an oil string or liner, perforated where it penetrates the oil-producing strata with numerous round holes or slots to admit fluids to the well. These perforations are sometimes equipped with screens of various types, which allow the oil to pass but exclude the sand which tends to flow into the well with the oil and gas. More complete protection against sand incursion is secured by "gravel-packing" the perforated section.

Types of Casing Perforations

Perforations in the oil string or liner may be formed before the pipe is run into the well, or after it is in place in the well. Preperforated pipe may be "shop-perforated" with rows of round holes or slotted with milling tools or with the oxyacetylene torch. Perforating in place

in the well is accomplished with the aid of the gun perforator or with a mechanical perforating device.



(Courtesy of Emsco Derrick and Equipment Co.)

FIG. 234.—Screen pipe with horizontal undercut milled slots.

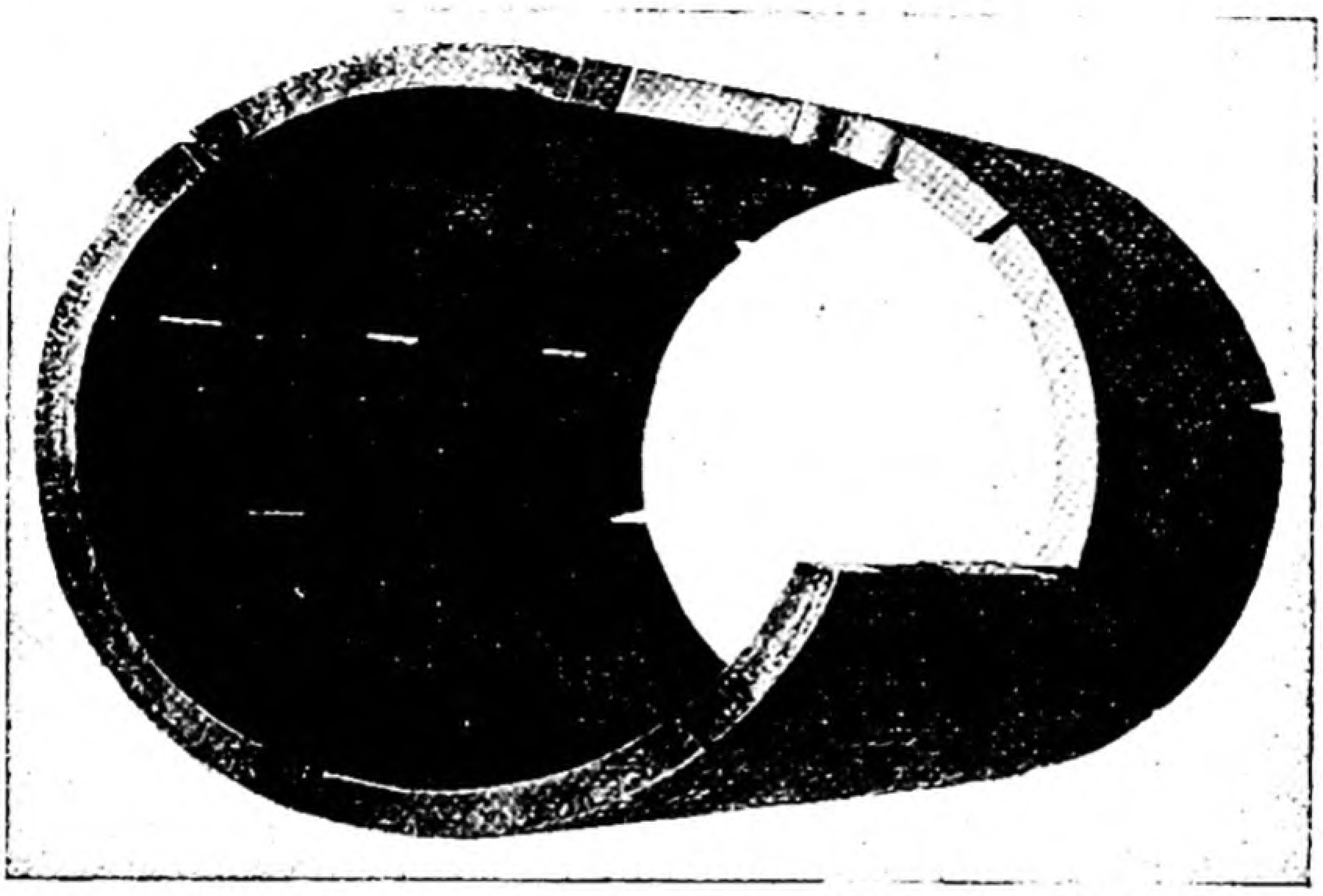
Shop-perforated pipe may be prepared in the machine shop with the aid of the drill press by boring round holes which may range from ⅛ to ¾ in. in diameter, depending upon the nature of the oil-bearing material and whether or not they are to be covered with some type of screen. The holes are bored in longitudinal rows, 30, 45 or 60 deg. apart, on the circumference of the pipe (*i.e.*, 6, 8 or 12 rows), with the holes 4 or 6 in. apart and staggered in alternate rows. The number of holes and their spacing will depend upon the size of the pipe, care being taken to avoid undue weakening of the metal which would, perhaps, result in subsequent parting or collapsing in the well. The round holes of shop-perforated pipe admit unconsolidated sand freely, and in a formation containing it must usually be screened.

Slotted Pipe.—A type of perforated pipe that is more successful in sand exclusion has narrow slots cut in it with a milling machine or with the oxyacetylene torch. Narrow slots are usually preferred, but it is scarcely practicable to cut them less than 0.01 in. wide and they are occasionally as much as ½ in. The length of the slots is usually 1.5 to 3 in. and they are aligned in rows with the longer dimension either parallel with or at right angles to the axis of the pipe.

Mechanically cut slots are usually milled from the inside by methods that produce a slot somewhat wider on the inside surface of the pipe than on the outside. Slots formed in this way have a V or keystone cross section which possesses minimum clogging tendencies. Figure 234 illustrates a type of screen pipe having rows of horizontal, mechanically cut slots, spaced ¾ to ½ in. apart. This pipe has from 78 to 260 lin. in. of slot opening per foot of pipe (depending upon the diameter) and yet retains 80 to 85 per cent of its original collapsing strength. To facilitate setting and pulling it is constructed with flush joints.

Kobe heat-treated screen pipe, a popular slotted pipe, is manufactured by precision methods involving the simultaneous use of a number of

oxyacetylene torches controlled by automatic mechanisms involving patented features. The slots are undercut 6 deg. and the edges are casehardened by the flame-cutting process, better to resist the scouring effect of fine sand. The slots are disposed longitudinally in staggered rows, and tests indicate that the slotted pipe retains 96 per cent of its original bending strength and 98 per cent of its original tensile strength. The slots may be of any desired length, but are preferably $1\frac{1}{2}$ in., and they may be cut in any width ranging from 0.03 to 0.25 in. Two rows of slots per inch of diameter are usually provided. The slotted area varies from 0.6 to 3 per cent of the surface area of the pipe, averaging 2 per cent (see Fig 235).

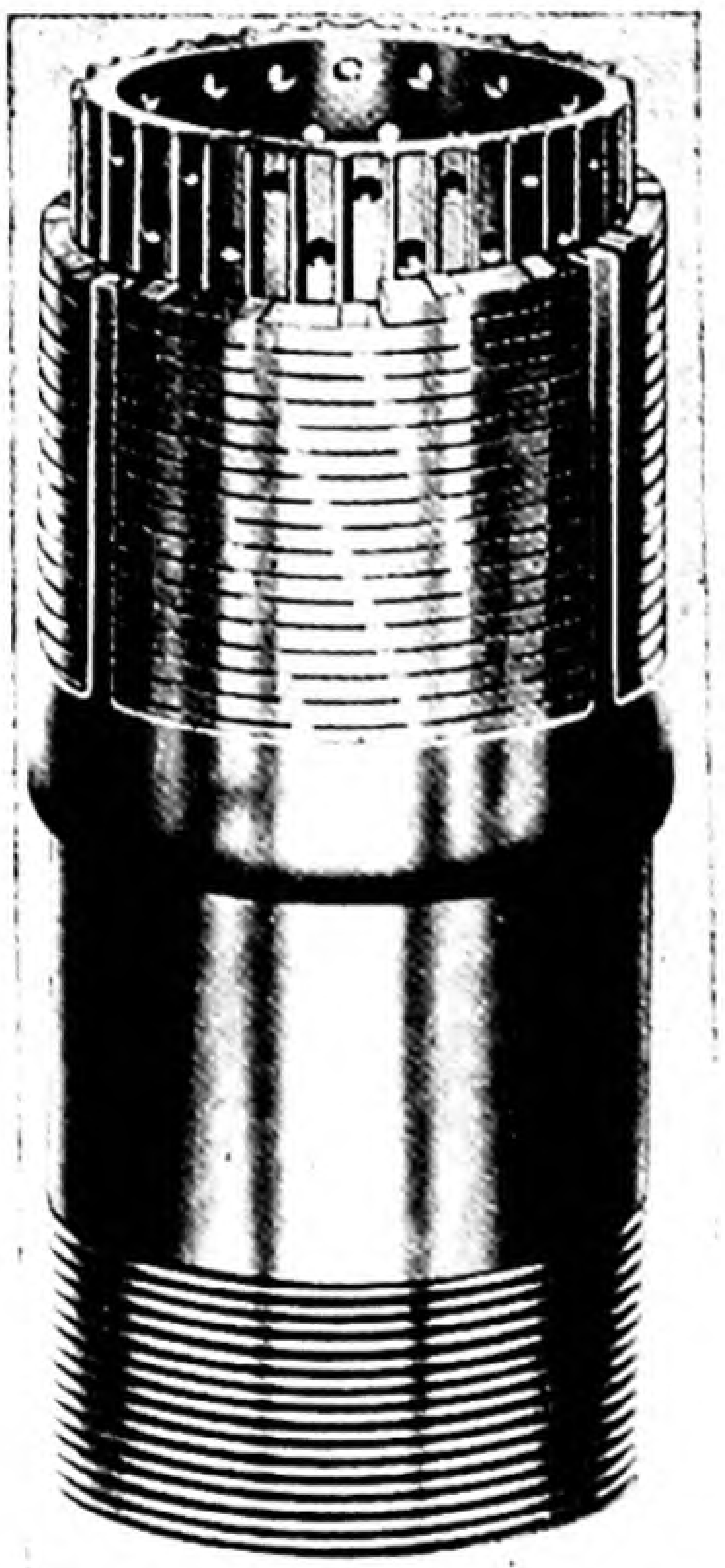


(*Courtesy of Kobe, Inc.*)
FIG. 235.—Kobe slotted pipe.

Screens on perforated pipe are of two general types: (1) a variety made by wrapping closely spaced coils of wire about the pipe, over the perforations, and (2) the so-called "button screen," in which the screen is cast in a small disk which is pressed or swaged or screwed into a circular perforation. In the construction of the wire-wrapped type of screen, the perforated pipe is placed in a lathe and the wire wrapped on as the pipe revolves. The size of wire and spacing of coils will depend upon the size of sand particles to be excluded and the gravity of the oil. Round wire was formerly used but, inasmuch as coils of round wire form wedge-shaped spaces which are readily clogged by accumulated sand, a wire of angular form, often of keystone cross section, is preferable. Projecting lugs at intervals along the wire maintain uniform spacing between coils. The wire presents a smooth exterior surface with the smallest side of the screen opening on the outer surface. This ensures any sand grain that can penetrate the outer opening a free passage through the screen and reduces clogging tendencies. After the wire

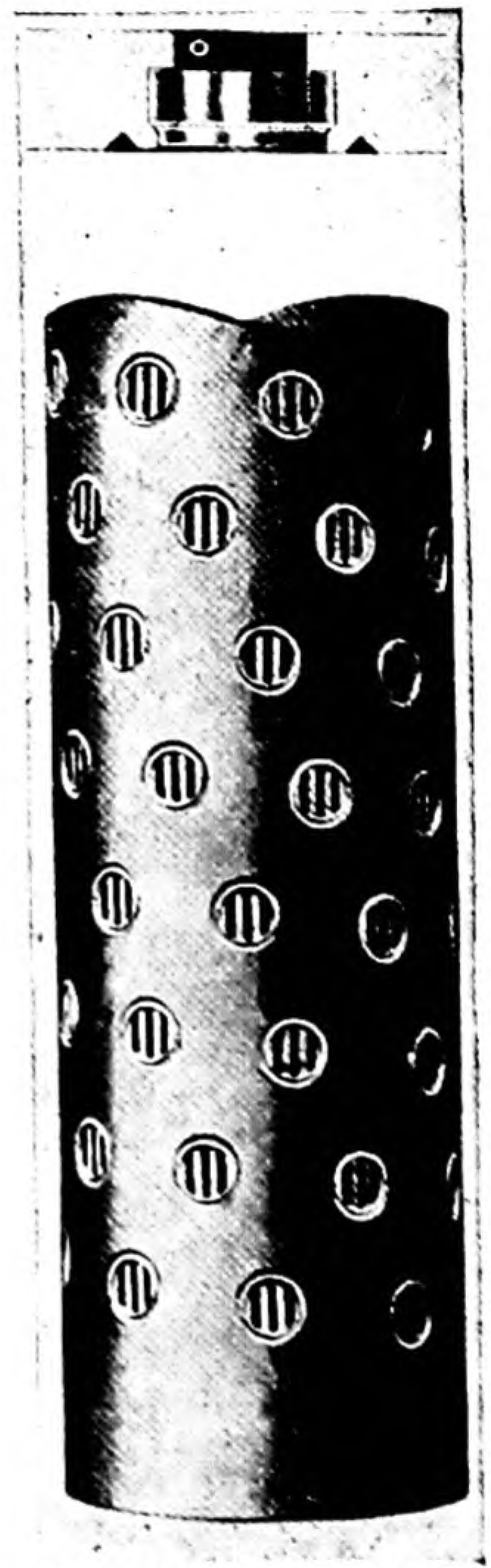
coils are in position on the pipe, they are brazed or welded together by longitudinal metal strips. The surface of the pipe may be ribbed or knurled to provide channels beneath the wire to the perforations. Figure 236 illustrates a wire-wrapped screen of this type.

Button-screen pipe is prepared by inserting in round, countersunk perforations separately fabricated "buttons," which present a series of



(*Courtesy of the Howard Smith Co.*)

FIG. 236.—Stancliff wire-wrapped ribbed screen.



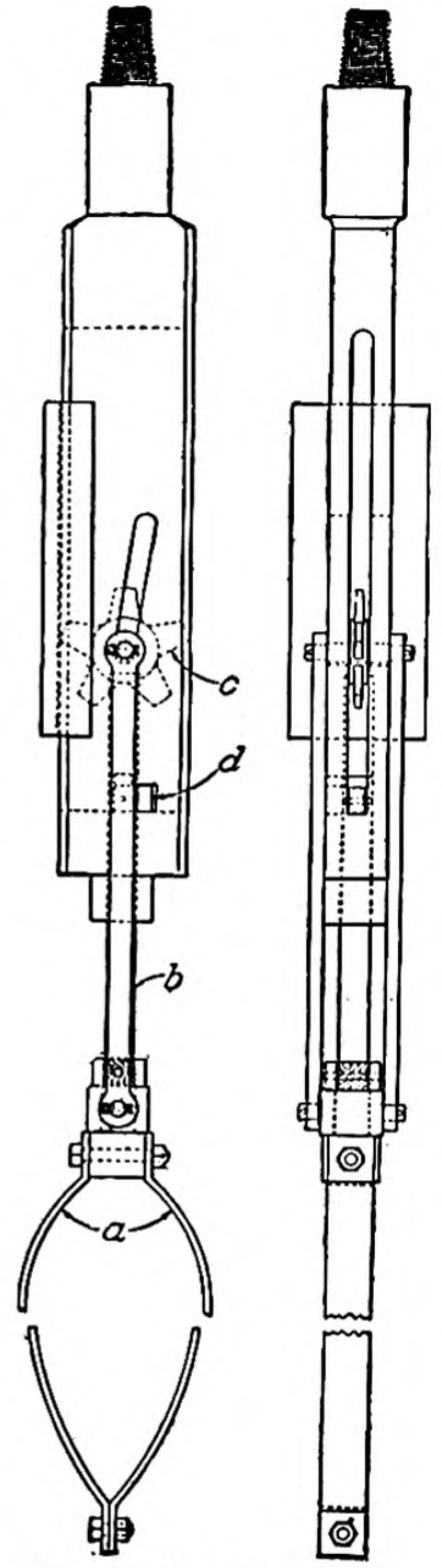
(*Courtesy of the Howard Smith Co.*)

FIG. 237.—Button-screen pipe. Above: detail illustrating method of fastening screened button in countersunk hole in outer surface of pipe.

narrow slot-shaped openings for passage of fluids. The buttons range in diameter from $\frac{1}{2}$ to $1\frac{1}{2}$ in. and are made of brass, hardened or stainless steel or drillable metal to meet varying well conditions. They may be either screwed into threaded perforations or retained in the perforations by calking the outer edge (see Fig. 237). Button-screen pipe presents a flush exterior surface to the wall of the well, may be easily washed and may be handled with slips.

Perforating Casing in the Well with Mechanical Perforators.—Until the development of the gun perforator, perforation of casing in the well, when necessary, was accomplished with the aid of mechanical casing perforators. Of these, there are two principal types: (1) the single-knife perforator, similar in many respects to a casing ripper (see Fig. 219), and (2) the wheel-knife perforator, equipped with one, or sometimes two, star-shaped wheels, the points of which, when brought to bear against the inside of the pipe, cut slots in it.

Figure 238 illustrates a perforator of the wheel-knife type. It is operated on tubing and depends upon a spring *a* and mandrel *b* for setting the knife *c*, which is shaped like a five-pointed star. A lug *d* on the mandrel prevents the knife from moving out of its position within the body of the tool while it is being lowered into cutting position but, when the depth is reached at which it is desired to begin perforating, turning the tubing releases the lug from its recess. Further lowering of the tool forces the mandrel upward, pressure of the spring on the end of the mandrel holding the latter stationary as the tool is lowered. As the body of the tool is lowered over the mandrel, the wheel knife mounted on the upper end of the mandrel is forced up the inclined slot until the points bear against the pipe. Further downward pressure on the tool causes the knife to revolve, punching a hole as each point of the knife is forced against the pipe. After one vertical row of holes is cut in this way, the tool is raised to its original cutting position, turned through 90 or 180 deg. and again forced downward. Double-knife perforators, which cut two rows of perforations at once, have a tendency to distort the casing if used on thin-walled pipe.



(*After E. W. Wagy, U. S. Bur. Mines Tech. Paper 247.*)

FIG. 238.—"Star" perforator. *a*, spring; *b*, mandrel; *c*, knife; *d*, lug.

Casing perforators should be rugged since the duty imposed is very severe, and they should contain as few working parts as possible. Although manufacturers of mechanical casing perforators contend that their machines are universally positive and reliable in action, the best types occasionally fail to accomplish their intended purpose. In some instances. casings drawn from wells have been found to have been merely

dented by the perforating machine, or only partly perforated. Operators have thus been led to believe that their wells were small producers or barren, whereas if the casing had been properly perforated they would have been good producers. Perforators are also occasionally responsible for ripping or splitting the casing, a series of misplaced perforations sometimes so weakening the pipe that it collapses or parts in the well.

Gun-perforating Casing in Wells

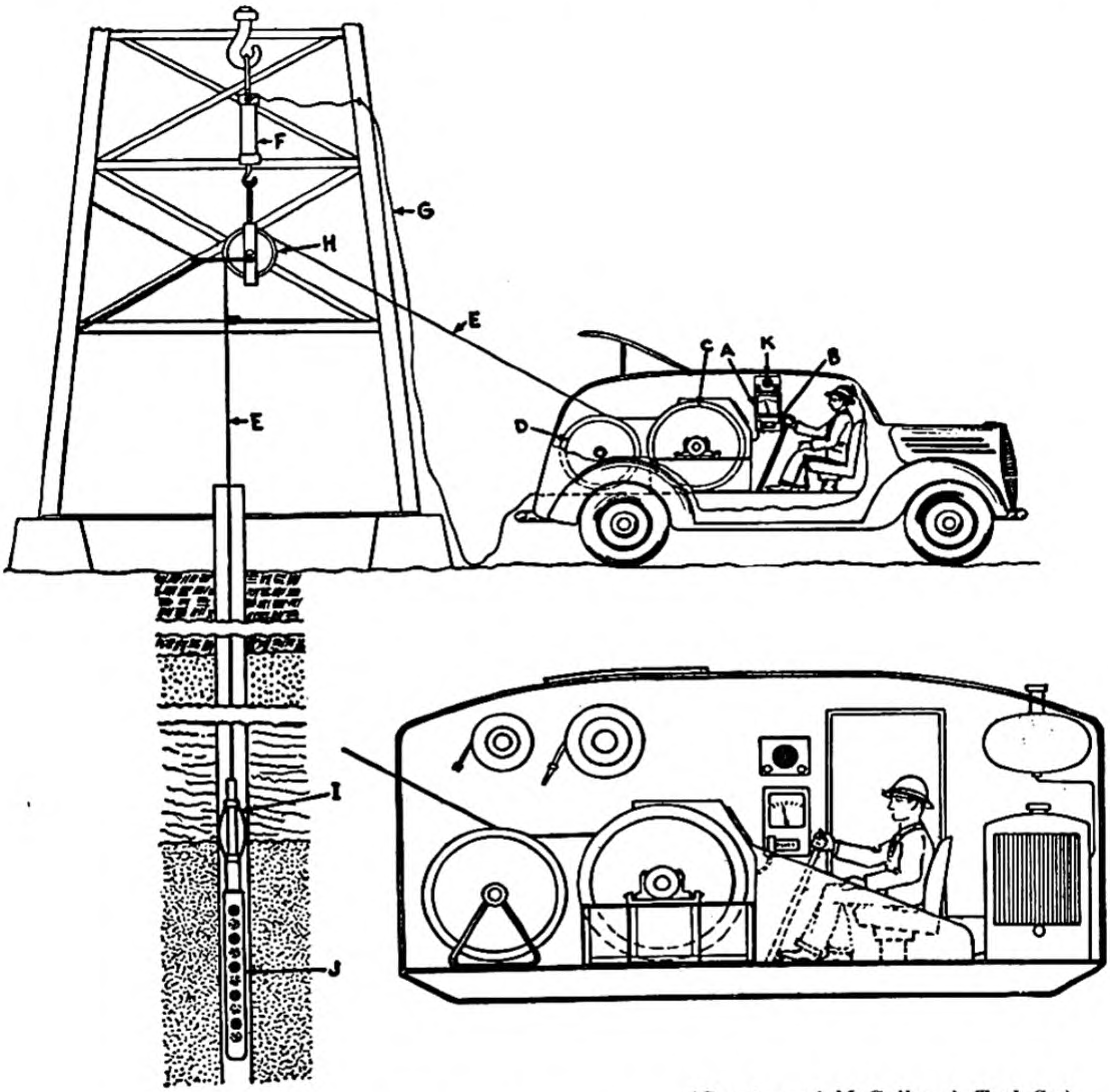
Frequent necessity for perforating casing after placement in the well, and unreliability of most types of mechanical perforators, led to the development of the gun type of casing perforator. In this device conical-pointed alloy steel cylinders are projected with the aid of a powerful explosive from guns mounted in a substantial cylindrical steel bar lowered within the casing. The projectiles, which are usually 0.45 in. in diameter but may be smaller or larger, are capable of penetrating several inches of steel casing and surrounding cement, forming clean-cut round holes through the casing and into the wall rocks wherever desired. Through gun perforations of this character, oil and gas production may be secured from the surrounding formation, or cement slurry may be forced in cementing operations. Acid treatment of wells to increase production is also promoted by gun perforating.[44]

Gun perforating is customarily done by a service organization that sends its specialized equipment and skilled personnel to the well and makes such perforations as may be required on a contract basis.

Gun perforators are available in a variety of different styles and sizes, designed to fire from 2 to 25 shots, one at a time in rotation, and at whatever depth desired without the device being withdrawn from the well. The mechanism is controlled and fired by electricity transmitted down into the well through a single conductor of stranded copper wires built into an insulated, steel-shrouded cable which also suspends the perforator in working position in the well casing. Above the well head, the cable passes over a sheave which operates a depth-measuring and recording device. The surplus cable is reeled on a hoisting drum mounted on the bed of a motor truck, which also carries power development and electrical control equipment (see Fig. 239).[40,45]

A commonly used type of gun perforator employed by the Lane-Wells Co., pioneers in the development and commercial exploitation of gun-perforator equipment, is illustrated in Fig. 240. This is a 20-shot gun, the firing chambers being arranged spirally about the gun body in pairs diametrically opposite each other. Details of design of the firing chambers and the usual form of the projectile fired are illustrated in Fig. 241. The firing chamber consists of a cylindrical body designed to screw securely into the gun body with features that prevent admission of well fluid until

after the shot is fired. In the recess within the firing chamber is placed a cartridge containing from 65 to 140 grains of a special grade of smokeless gunpowder. The explosive cartridge is supported between electrical contact springs, connected through the powder by a filament of nichrome wire. The projectile is held in position against the explosive by a supporting shear disk. A little free air space separates the conical point of the projectile from the fluid-seal disk which protects the barrel against water



(*Courtesy of McCullough Tool Co.*)

FIG. 239.—Arrangement of equipment used in gun perforating. *A*, weight-indicator dial; *B*, depth indicator; *C*, hoisting drum; *D*, line-measuring sheave; *E*, operating line; *F*, electrically operated weight indicator; *G*, weight-indicator cable; *H*, derrick sheave; *I*, safety cage; *J*, gun perforator; *K*, two-way speaker system for communication with operator at well head. Lower right: skid-type service unit.

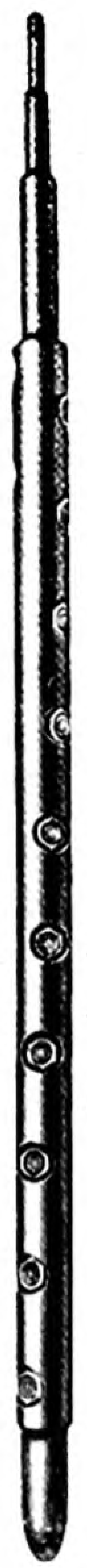
entry. The explosive is fired by the nichrome wire filament, which is heated to incandescence by passage of d-c electricity of suitable voltage.

An elaborate wiring system provides separate conductors to connect each of the firing chambers with the controller unit built into the upper end of the gun. The controller unit consists of a solenoid-operated pawl and ratchet actuated by a flow of electric current down through the suspending cable from the surface control panel. Closing a circuit in the control apparatus at the surface advances the pawl one notch

in the ratchet and connects the firing circuit with a different firing chamber. In the lower part of the gun body is an air chamber the fluid seal of which connects directly with the well fluid. Air here imprisoned under well pressure absorbs some of the shock of the explosion when a shot is fired and permits the well fluid to be displaced momentarily from the space through which the projectile must pass.

The cable used in suspending the gun perforator in the well is 7⁄16 in. in diameter and has a tensile strength of approximately 9 tons. In the center of this preformed steel cable is an electrical conductor core, insulated to withstand submersion in high-pressure liquid and the high temperatures encountered in deep wells. This conductor cable, 8,000 to 15,000 ft. long, is spooled on a large hoisting drum mounted on the bed of the service truck and driven by the truck engine.

The depth-measuring device consists of a sheave assembly suspended over the well with guys to the four corners of the derrick and indicating and recording mechanism in the service truck. The cable, on which the gun perforator is supported in the well, passes over the sheave, revolving the latter at a speed proportional to the rate of movement of the perforator through the well. As the sheave revolves, it operates a Selsyn motor which is connected by an electrical circuit with a synchronized motor in the service truck. These motors make one revolution for every foot of cable that passes over the sheave. The motor in the service truck is geared to a depth meter which accurately indicates the depth of the perforator in the well at all times. The upper portion of the sheave assembly unit functions as the actuating member of a weight-indicating device which is helpful in locating the bottom of the hole, the fluid level in the casing or any bridge or obstruction which



(*Courtesy of Lane-Wells Co.*)
FIG. 240.—Gun perforator.

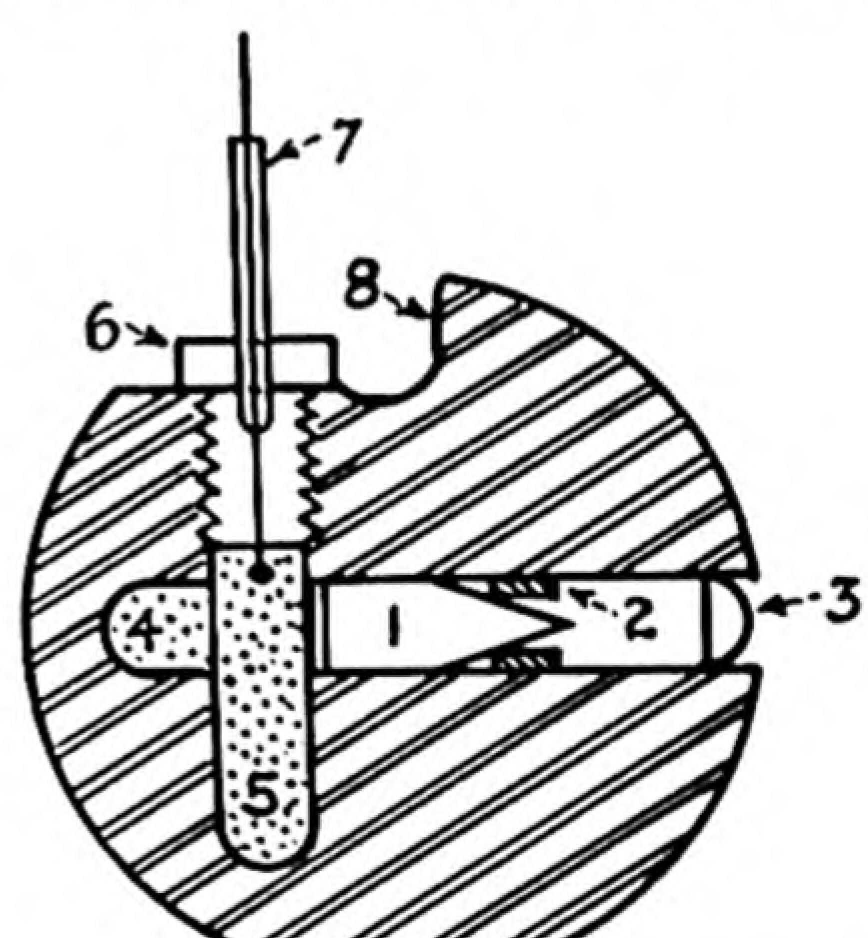


FIG. 241.—Construction of "gun" used in Lane-Wells gun perforator. 1, bullet; 2, rubber bullet retainer; 3, seal cap; 4, short cartridge; 5, long cartridge; 6, fuse plug; 7, fuse-pin assembly; 8, steel body of tool.

may suspend the gun perforator in the casing. Seated before the control panel in the service truck, the operator at all times may know the depth of the gun perforator below the derrick floor or other reference horizon, so that an accurate record of the depth and pattern of perforations in the casing may be preserved.

The McCullough Tool Co. has pioneered development of another type of gun perforator, in which all of the shots loaded in the gun are fired simultaneously. Lowered on a conductor cable, the shots may be fired electrically; or, on a sand line, by

impact of a go-devil dropped from the surface. Projectiles which may range from ¼ to 1⅛ in. in diameter are fired from guns 6¾ in. in diameter.

Principles of Screening

Consideration of the character of the reservoir rock, the pressure conditions, gas-oil ratio and other related factors will indicate whether or not screens are necessary or desirable. In many cases, perforated pipe without screens will exclude sand sufficiently and will offer less resistance to the passage of oil. Under some conditions, it is necessary to allow the finer sand particles to flow into the well with the oil if maximum production is to be maintained. In other cases, however, screens will be desirable in order to prevent incursion of excessive amounts of sand, with consequent increased expense due to the necessity of lifting it to the surface, wear on the pump parts, tubing, valves and lead-line fittings, and the necessity of separating it from the oil after it reaches the surface. Furthermore, removal of large quantities of sand from formations about the well causes caving of overlying strata, which may collapse or bend the liner and permit water to enter the oil sand from an overlying source.

It is important that liner screens be made of a material resistant to corrosion by chemically active ground waters and sulphur compounds to which they are sometimes subjected in service. Brass and stainless steel are sometimes used for this purpose. In addition to resisting corrosion, the material selected should resist the cutting or scouring action of fine sand which is sometimes carried through the perforations at high velocity by the flowing gas and oil in which it is entrained. Use of hardened steel confers some protection against sand scouring. In high-pressure flowing wells, it is advisable to protect the well equipment by maintaining an appropriate back pressure by restricting the outlet, thus reducing flow velocity and minimizing sand-scouring action.

There has been considerable experimentation in attempting to determine the best size and form of screen opening. In an earlier period, the "shutter" form of screen opening was favored on the theory that sand caves into the screen openings from the walls of the well under the influence of gravity. The shutter type of screen has openings that are inclined upward from the outside surface to the inside surface of the pipe. It seems probable, however, that in most cases the sand grains are actually suspended in the oil or are swept through the screen openings in a stream of rapidly flowing gas. Under such conditions, the sand grains flow with the oil and gas, quite independently of its natural angle of repose, and the form of the opening becomes of little or no importance.

The size of screen opening must be proportioned to the average size of the sand grains which are to be excluded. Experimental tests have indicated that a screen opening may have a maximum width about 2½

times the diameter of the sand particle that it is intended to exclude. The sand grains will bridge on the screen if this ratio of screen opening to size of sand particle is not exceeded. One authority states that if the screen openings are not larger than the minimum grain size of the coarsest 15 per cent of the sand, the coarser grains will bridge over the screen openings and form a sand filter, even though there is a high rate of flow of oil and gas through the screens. If no water is present, the oil-well pump, gas-lift or free-flowing well, is able to handle a limited amount of sand without excessive wear or loss of efficiency, and usually no effort is made to exclude the very fine "float" sand which passes through any kind of screen that will admit a highly viscous oil. The screen openings should not be so small as entirely to exclude the finer sands, which will otherwise accumulate about the screen openings and retard flow of oil into the well. On the contrary, they should be of such size that application of a swab will draw much of the accumulated loose material into the casing so that it can be bailed out and the perforations and screens thus cleared.[38,39,41,46]

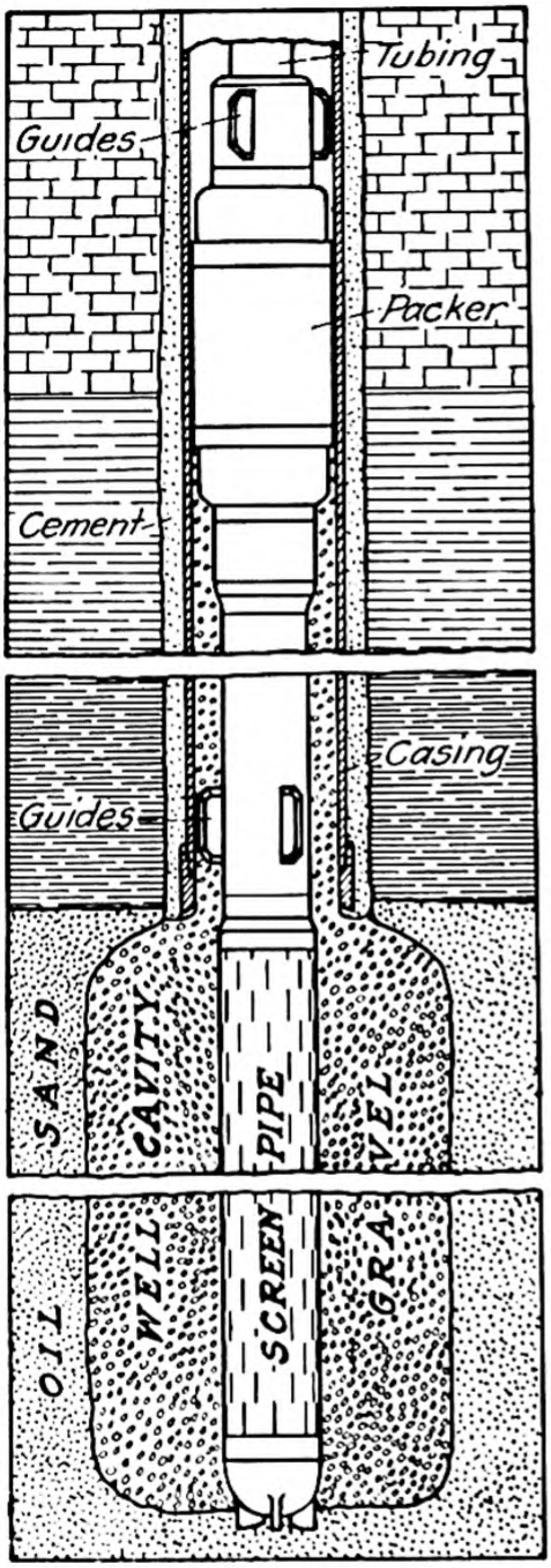


Fig. 242.—Objectives sought in gravel-packing oil wells.

Gravel Packing for Wall Support and Sand Exclusion

The practice of surrounding with gravel or coarse sand the perforated liner through the producing formation in an oil or gas well has come to be known in the petroleum industry as "gravel packing." Figure 242 illustrates the objective sought. Many advantages are visualized for the well equipped with a gravel-packed liner, all of which tend to increase its production efficiency. When properly placed in the annular space between the wall of the well and the perforated liner, gravel supports the walls, prevents caving of loose material against the liner and serves to restrain sand from unconsolidated and disintegrating strata so that it may not enter the well. More effective screening of sand, possible by this means, diminishes the destructive influence of sand scour-

ing on well equipment and tends to reduce maintenance costs. Equipment repairs and well clean-out operations are less frequent and the well is able to produce for a greater part of the time than would otherwise be the case. The well so protected is therefore capable of maintaining a larger average monthly production rate. With gravel to sustain the walls of the well, it is possible to form and maintain a hole of larger diameter through the producing formation without elsewhere increasing the normal diameter of the well or that of the well casing. The larger diameter hole through the producing zone results in increased production efficiency.[49,50,51]

Principles of Gravel Packing.—To be effective in sand screening, it is essential that the perforated liner be completely enveloped through the producing formation with a gravel sheath of suitable thickness; that the perforations in the liner be of such size as completely to exclude all the gravel and that the gravel particles be of such size and so compacted as to permit only the very smallest sand particles to pass through with the formation fluids into the well. The coarser sand particles must bridge over the openings between the gravel particles at or near the sand-gravel interface. These coarse sand particles in turn serve as a barrier for finer sand grains and thus, in time, a combination gravel-sand screen is built up that is stable for the particular flow conditions obtaining.

The size of the gravel particles should be proportioned to the prevailing size of the sand particles to be restrained. Sand grains are of assorted sizes and shapes and it is difficult to apply mathematical principles to them. As a matter of practical application, however, it has been found convenient to make a screen analysis of a representative sample of the reservoir sand, then plotting the results on a cumulative weight percentage graph on semilogarithmic paper (see page 699) and using the size of sand grain corresponding to the 10 per cent point on the graph as a reference guide. Laboratory tests indicate that a stable bridge will frequently form when the size of gravel particles is as much as thirteen times the 10 per cent sand-grain size; but that, for dependable screening action, the gravel should preferably be less than eleven times the size of the sand particle corresponding to the 10 per cent point on the screen analysis graph. Some authorities recommend a ratio as low as 8. Application of this principle leads to the use of gravel particles of 4 to 10 mesh (0.185 to 0.065 in.) in dealing with most oil sands. The gravel should be screened within narrow size limits: that is, 6 to 8 mesh, 8 to 10 mesh, etc. Permeability of the gravel envelope is not seriously impaired by using gravel as small as 14 mesh (0.046 in.). Selection of the appropriate gravel size is not so simple a problem as might appear from the rule quoted above, for on careful analysis it is found that other factors than the relative diameters of the sand and gravel particles—such as the grain-size distribution of the sand and the flow velocity and fluid viscosity of the entering fluid—have a bearing on the effectiveness of the screening action. Variations in the production rate of a well may thus allow an established bridge to fail, and it must then be reformed before the gravel screen again becomes effective.*

Opinions vary concerning the necessary thickness of gravel to ensure security against sand infiltration. Some investigators have found that a layer of gravel only five gravel-grain diameters thick is sufficient to form a secure bridge; that if the gravel

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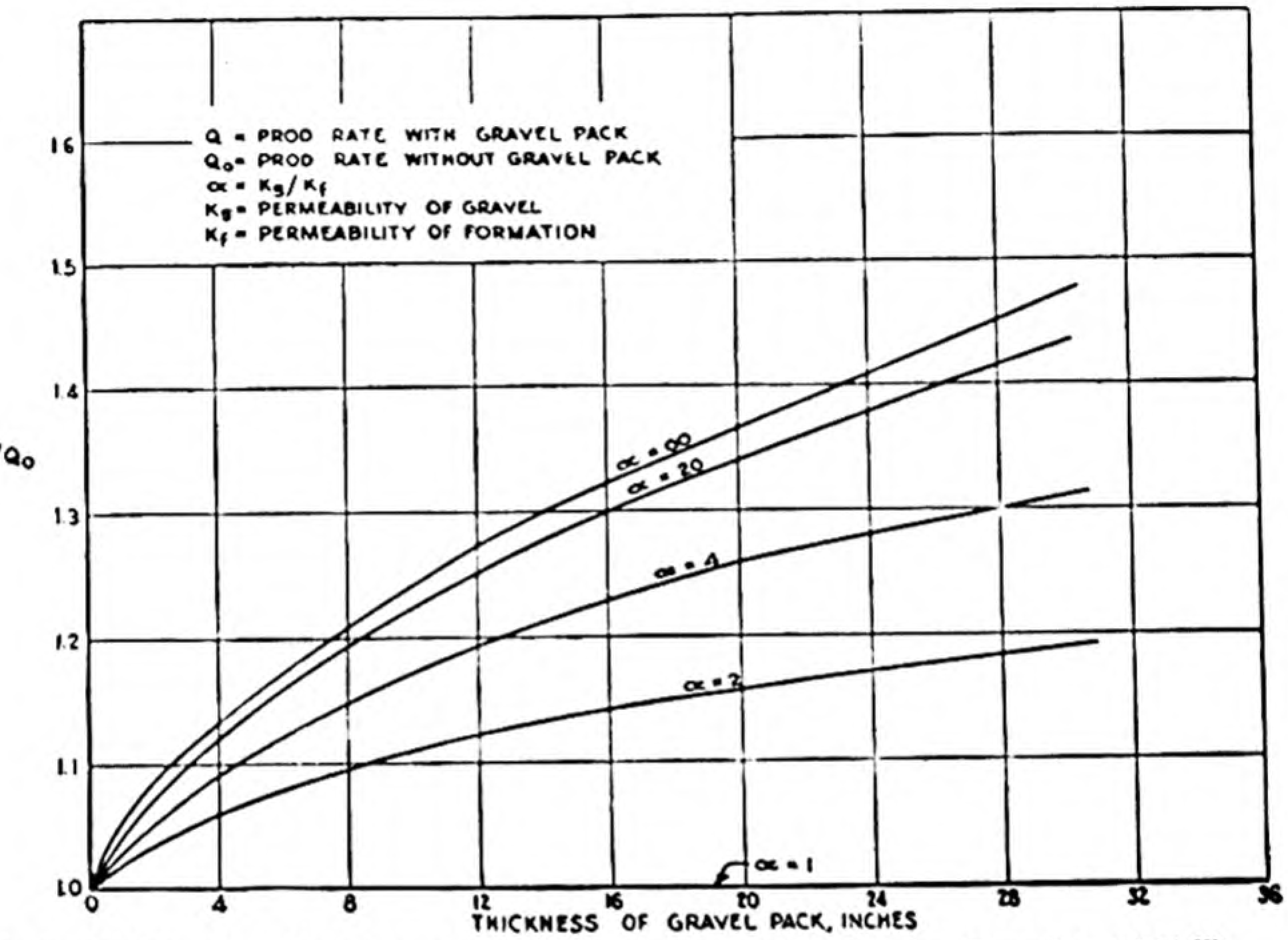
* Much of the material in this section originally appeared in an article by the Author, published in *Petroleum Engr.*, Annual Number, July 1, 1942, pp. 81–90.

is of suitable size and properly compacted, the sand will not penetrate beyond the outer few layers of gravel. However, in view of the possibility of occasional readjustment of sand particles, as suggested in the preceding paragraph, it appears that a thicker gravel bed would give greater security. Experiments indicate that no gravel screen is completely effective, inasmuch as there will inevitably be some movement of the smallest sand particles through the gravel and into the well with the oil. Indeed, it is probably an advantage to encourage production of a certain amount of fine "float" sand, for only by so doing may an outer envelope of coarse sand about the gravel envelope be achieved and the clogging influence of the finer material be removed.

In order that the gravel envelope shall restrict flow as little as possible, it is important that its permeability be high. Fortunately, even the smallest sizes of gravel necessary to control sand movement have permeabilities many times that of the



(After K. E. Hill in Am. Petroleum Inst., "Drilling and Production Practice, 1941.")

FIG. 243.—Graphs showing relationships existing between thickness and permeability of gravel packs and rate of production of wells.

reservoir sand. The permeability of reservoir rocks seldom exceeds 3 darcys, while that of the gravel envelope ranges from 1,150 darcys for 8- to 10-mesh material to 3,700 darcys for 4- to 6-mesh gravel. Experiments have also determined that the sand bridge formed at the sand-gravel interface has a permeability of at least thirty times that of the reservoir sand.[53,54]

If the diameter of the well through the reservoir rock is mechanically reamed or otherwise enlarged before inserting the liner and surrounding it with gravel, material benefits through increased production efficiency are attained. Gravel support of the walls of the well cavity assures preservation of all of the benefits of superior production efficiency that go with large-diameter wells. Large-diameter wells develop larger initial productions, larger productivity indices and potential ratings and greater ultimate recovery than otherwise similar smaller diameter wells. The graphs of Fig. 243, derived from the results of experimental research, indicate clearly the advantage of the enlarged gravel-filled well cavity from the production standpoint. Thus, it appears that a well with a gravel pack 8 in. thick and developing a permeability when bridged of twenty times that of the producing formation in a well of normal diameter without

the gravel pack, produces at a rate approximately 1.2 times that of the ungraveled well. This assumes a 6-in. liner. If gravel-filled cavities 10 ft. in diameter could be formed, as seems possible by hydraulic methods (see "Oil Field Exploitation," pages 373–375) in semiconsolidated formations, the rate of production could be substantially doubled.

Gravel-packing Technics.—Gravel-packed liners are of three types: (1) the conventional type, in which the perforated liner is placed in the well and later gravel is circulated into the annular space about the liner with the aid of a circulating fluid; (2) the gravitational type, in which the gravel is allowed to fall or sink through the well fluid by gravity into an enlarged well cavity and the perforated liner is then driven, rotated or jetted into the accumulated gravel; and (3) the prepacked liner, in which the annular space between a perforated liner and an outer concentric screen is filled with gravel in the manufacturer's plant, the prepacked sections being shipped to the field and connected end to end as they are inserted in the well. Each type of gravel pack has certain advantages and disadvantages and the oil producer must choose the one best adapted to the conditions in the particular well where it is to be used.[57,58]

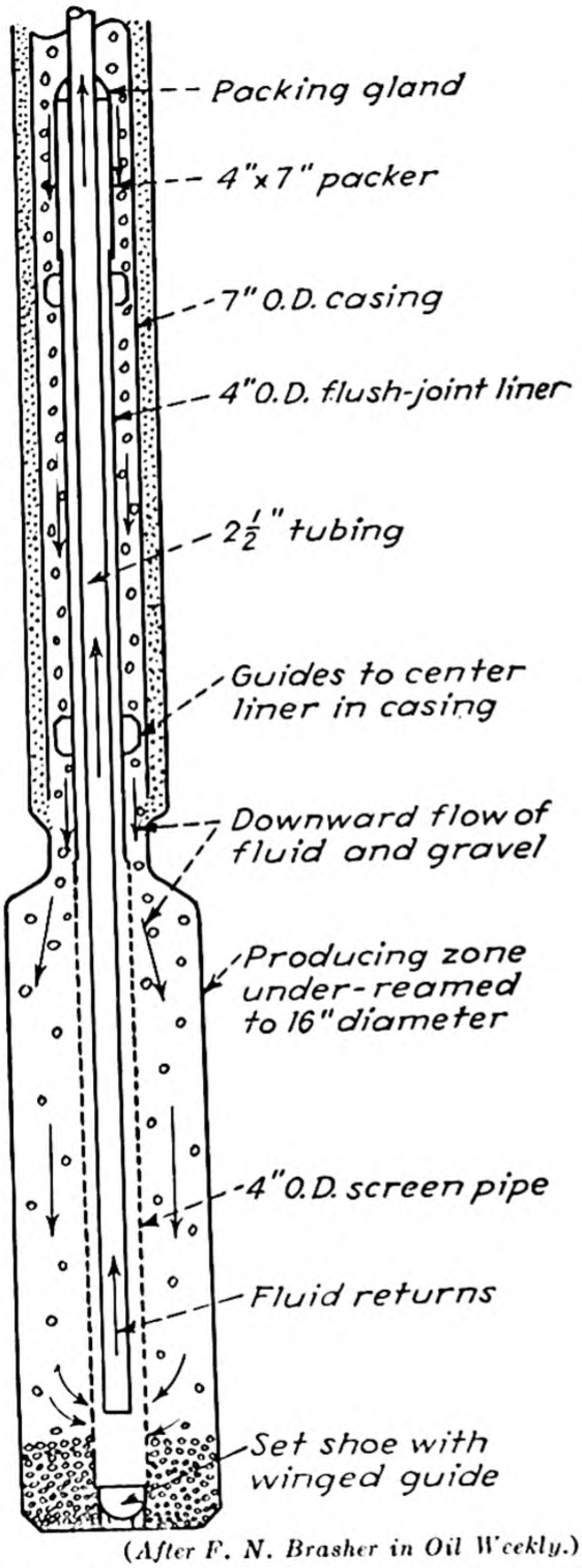
Gravel packing by Circulation Methods.—When gravel is to be placed about a liner in a well by circulation methods, it is usual first to under-ream or wall-scrape the well throughout the interval in which the gravel is to be placed. If a 5¾-in. O.D. liner is to be used, the reamed hole may be from 16 to 20 in. in diameter, thus leaving a space of 5 in. or more about the liner in which to place the gravel. If the interval to be graveled is a long one, centering guides may be placed on the outside of the liner to assure that it is centrally placed in the enlarged hole. Reaming removes all caked mud from the walls of the well through the productive zone and detrital material is thoroughly circulated out of the well before gravel is placed. Crude oil or drilling fluid of high colloidity and low density is used as a circulating fluid. Thus, the pore spaces of the reservoir rock at the wall of the well and the gravel particles are left covered with a very thin mud sheath that is easily disintegrated by pressure washing.

After the liner is placed in the well, clean, washed and closely sized gravel is circulated into the well by adding it at the surface, a little at a time, to a stream of circulating fluid forced down the well under pump pressure. Circulation may be either normal or reversed. In the former system, the fluid and entrained gravel are forced downward through a column of drill pipe or tubing which supports the perforated liner on its lower end and extends through or about the liner, the gravel being discharged into the well cavity around the liner, while the circulating fluid returns to the surface through the annular space. In reverse circulation, the descending stream of fluid and entrained gravel passes down through the annular space, the gravel is deposited in the well cavity and the fluid returns to the surface through the tubing or drill pipe. Special well equipment in the form of packers, wash pipes, etc., are necessary in either case, and surface appliances have been devised for applying pump pressure and feeding gravel in regulated amounts to the descending stream of circulating fluid (see Fig. 244). Such work is customarily done by a service organization which, for a service charge, brings its special equipment and trained personnel to the well and guarantees successful completion of the operation. Introduction of gravel should be conducted in such manner as to assure that the annular space about the liner within the producing interval is completely filled and that, when in place, the gravel envelope will be substantially uniform in porosity and permeability and free of detrital material and clay accumulations. Under favorable conditions, it has been found possible by extrusion through perforations in the walls of the casing to place gravel by normal circulation methods in cavities formed around casing.

Thus far, the industry has preferred the reversed-circulation method of gravel placement, using specially prepared, clay-laden drilling fluid as the circulating medium,

and the technic of this process is now well developed. Reversed circulation has the advantage of comparative simplicity, and the downward movement of fluid and gravel into the well cavity assists in more thorough compaction of the gravel particles.

Use of clay-laden fluid as the placement medium leaves a mud sheath on the wall of the well and gelled clay in the pore spaces of the gravel envelope which, if allowed to remain, may seriously restrict later productivity of the well. The remedy for this condition lies in a thorough washing of the gravel envelope through the liner perforations after placement of the gravel is complete. Much may be accomplished, also, in preventing formation of thick wall sheaths, by proper conditioning of the fluid used in under-reaming and gravel placement. Use of lime muds that can later be disintegrated by treatment with inhibited acid is also a promising method.[55,56]

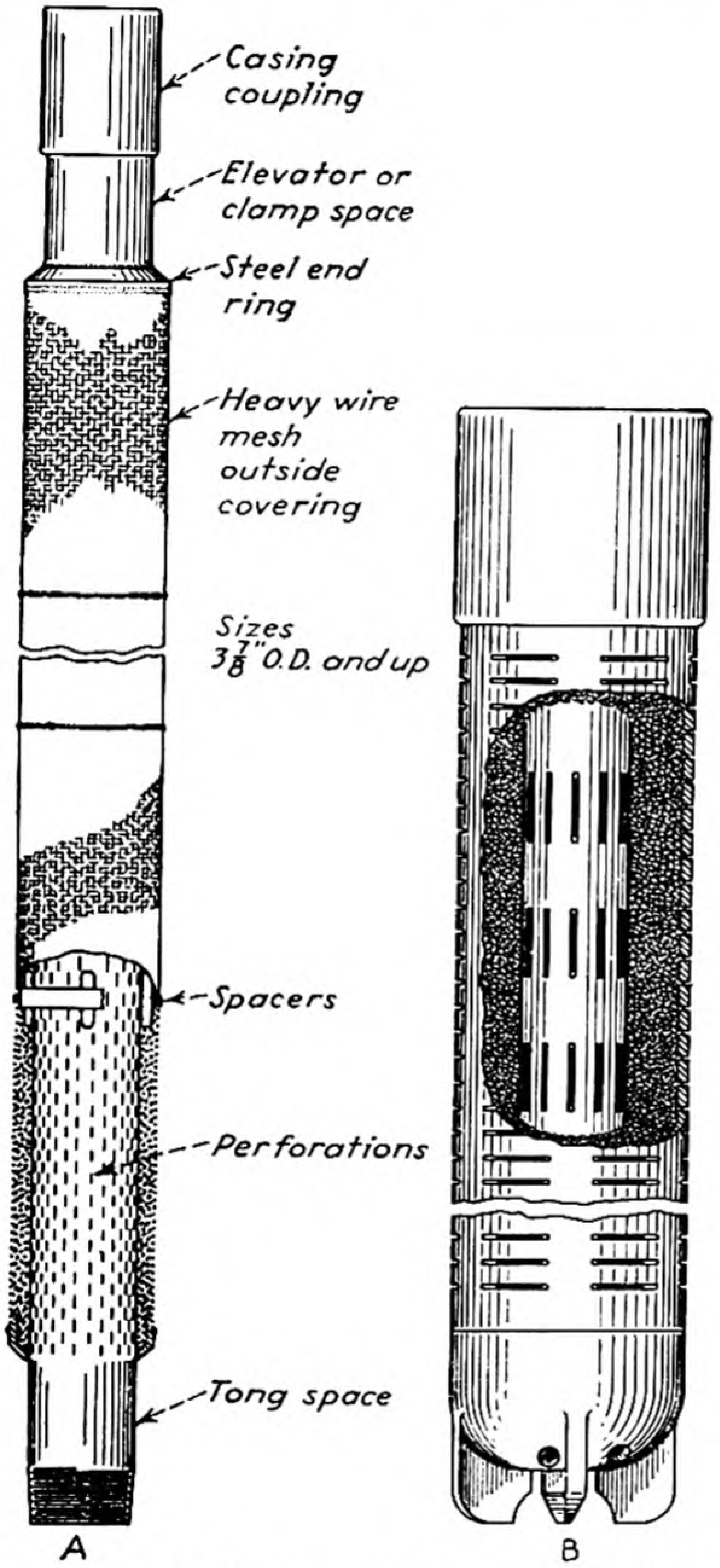


(*After F. N. Brasher in Oil Weekly.*)
FIG. 244.—Arrangements for gravel packing by reverse circulation.

When conditions permit of its use, oil would appear to be the ideal placement medium. With oil, there need be no clay accumulations to deal with and the walls of the well would be left oil-wet and capable of developing maximum permeability for subsequent production. Use of oil, however, is somewhat more difficult from a practical standpoint and may occasion no little inconvenience and expense in changing over from the usual clay fluid used in drilling operations. If oil is used as the circulating medium and there is any choice among available oils, a heavy, viscous one is preferable; but usually the crude oil produced in the field must be used for economic reasons.

Gravitational Gravel-placement Method. Depositing gravel in well cavities by gravitational methods is primitive and may be expected to give satisfactory results only when the well is comparatively shallow, the productive interval to be graveled is of no great thickness and the walls of the well are sufficiently stable so that they do not cave readily. In this method, a cavity is formed by mechanical or other means within the reservoir rock and sufficient gravel to fill the well cavity is simply poured down inside the casing. The perforated liner, equipped with a special shoe, is then lowered into the accumulated gravel. With this method, there is likely to be difficulty in maintaining the liner in the center of the gravel mass, especially if the producing interval is of considerable thickness.

Prepacked Liners.—Prepacked liners are available from several manufacturers and vary somewhat in construction and design. In each case, the liner is of the usual slotted type, with slots of such size as will prevent any movement of gravel particles through them. Concentric with the liner, and supported on it by spacing guides, is an outer screen constructed either of stout woven wire, perforated sheet metal or lightweight slotted-screen pipe. Gravel of appropriate size is compacted



A B C

Fig. 245.—Types of prepacked liners. *A*, Nelson liner; *B*, Layne and Bowler "Hydro-Pak" liner; *C*, Kobe liner.

within the annular space between the liner and the outer screen. Usually the gravel sheath is about ½ to ¾ in. thick, and is compacted by special methods, involving vibration or water action, which assure minimum porosity. Prepacked liners in lengths up to 40 ft. are prepared in the manufacturer's plant and shipped to the field, where the sections are coupled by collared joints like ordinary casing as they are inserted into the well (see Fig. 245). They are heavy and should be carefully handled

to avoid damage to the outer screen. The casing through which they are run must have an inner diameter at least 1 in. larger than the outside diameter of the outer screen. Thus, a 5¾-in. gravel-packed liner, as prepared by one manufacturer, has an over-all diameter of 7¼ in. and requires the use of a well casing at least 8⅝ in.

Relative Advantages of Prepacked Liners and Gravel Envelopes Placed by Circulation Methods.—Prepacked liners have the advantage that they require no special equipment or skill on the part of the operator in placing them in the well. They lend themselves to ordinary programs of well casing and are especially useful in dealing with multizone formations of considerable thickness. Though they provide but a minimum thickness of gravel about the liner for successful screening, it is assured that this envelope is continuous and of uniform porosity and permeability. The gravel is positively in place all around the liner and there are no open channels through which sand movement may occur. An important criticism of the prepacked screen, in comparison with the circulated gravel pack, is that it provides none of the advantages that result from preservation of the larger diameter hole. It uses a liner smaller than could be inserted in a hole of the size that must be drilled to receive it, and provides no support for the walls. Space necessarily left in the well around the liner permits the formation to close in about it. When this occurs, owing to structural weakness of the outer screen, the liner becomes frozen to the formation and cannot later be moved. The wire screen, or thin-walled sheet metal of which the outer screen is composed, is likely to become abraded by contact with the casing and wall of the well during insertion, and subsequently may deteriorate rapidly by corrosion. Openings in the outer screen become clogged with clay by scraping on the wall of the well during insertion, and may only imperfectly be cleaned by pressure washing after the liner is in place. It is also more difficult to remove the mud sheath on the wall of the well by washing through a gravel-packed screen. A properly designed gravel pack placed by circulation methods has none of these disadvantages. A circulated pack provides a thicker gravel envelope which affords better screening action, with less possibility of its pores being clogged by sand incursion. The walls of the well are positively supported so that they cannot cave or disintegrate. The superior productive capacity of the large-diameter hole is therefore preserved throughout the life of the well. Although the diameter of the well cavity through the reservoir rock may be large, the diameter of the hole through the overlying formations may be small. The advantages gained by use of the circulated gravel pack may thus be combined with the economies afforded by slim-hole drilling. Smaller and less expensive casings may be used.

Oil and gas may flow directly from the producing formation through a gravel pack placed by circulation methods, without contending with the restricting and clogging action of an outer, secondary metal screen. The circulated pack supports the liner and affords protection against vibration damage and column failure when it rests on the bottom of the hole. A liner enclosed in a circulated pack may be removed without damage at a later date by inexpensive methods of "washing over" or circulating out the gravel. Cement plugging, deepening or other well repair operations are thus facilitated. Prepacked liners generally cost more than circulated gravel packs.[49]

Methods of Setting Screen Pipe

A liner made up wholly or partly of screen pipe is assembled at the well head and lowered into its intended position in the well on a column of smaller diameter casing, tubing or drill pipe. The lower end may be equipped with a special shoe or foot piece embodying a back-pressure valve and a suspending tool which engages the lower end of the tube on which

the liner is lowered. Through this tube, fluid may be circulated down from the surface and out through the foot piece and back to the surface through the annular space between the liner and the wall of the well or outer casing, thus providing a means of clearing away accumulated clay and detrital material from the wall of the well, the annular space and the outer screen surfaces. To avoid buckling of the liner due to column action, arrangements may be made to suspend it so that it does not rest on bottom, from the next larger string of casing, usually the water string landed and cemented some distance above. For this purpose, a "liner hanger" is used, attached to the upper end of the liner, equipped with slips that are released to grip the inside surface of the casing a short distance above its shoe when the liner is in position. A "liner packer" may also be used to close the annular space between the casing and the upper end of the liner after it has been washed thoroughly by circulation. The hanger and packer are designed to permit free circulation through the annular space until released by a mechanism which collapses the packer so that its lead or neoprene packing rings are expanded to fill the annular space and grip the wall of the casing.

Bearing in mind the purpose of screen pipe and the weakening effect suffered by the metal as a result of the boring, cutting or punching of numerous holes, it is apparent that the liner should be so handled in the well as to avoid placing undue strain upon it, or great external friction which might displace the wire screening. Also, the screen openings should be left free from mud, sand or other material which might prevent free passage of oil through them. It is advisable to wash all accumulated mud and detrital material from the lower portion of the well before attempting to set screened pipe.

If the wall rocks are firm and free from accumulated clay, it may be possible to circulate the well thoroughly through tubing or drill pipe before running an oil string with suitably placed screen pipe on or near its lower end. In loosely cemented sands, however, a method should be adopted that will prevent contact of the screen pipe with the walls of the well until it is in place. This is accomplished by inserting the screen pipe as a liner, which must be small enough in outside diameter to pass within the oil string which penetrates the oil sand. The screen-pipe liner is plugged at its lower end and is lowered on a column of 2- or 3-in. tubing connected with the screen pipe by a casing adapter and a left-handed swaged nipple. The liner is lowered until it rests on bottom, and the oil string is raised until its shoe is about 10 ft. below the casing adapter on the liner. The tubing is then turned clockwise, unscrewing the joint at the left-handed swaged nipple, leaving the liner in the well with the adapter on top to serve as a guide for tubing or tools that may subsequently be lowered through it. The walls usually close about the

liner sufficiently after the oil string is raised to prevent the screen pipe from turning as the tubing is detached. Occasionally the oil string will become frozen, so that it is impossible to raise it in this way. It must then be perforated in the well, by mechanical means or by gun perforating, so that oil may pass, a liner of screen pipe being subsequently set inside if passage of sand through the perforations becomes serious.

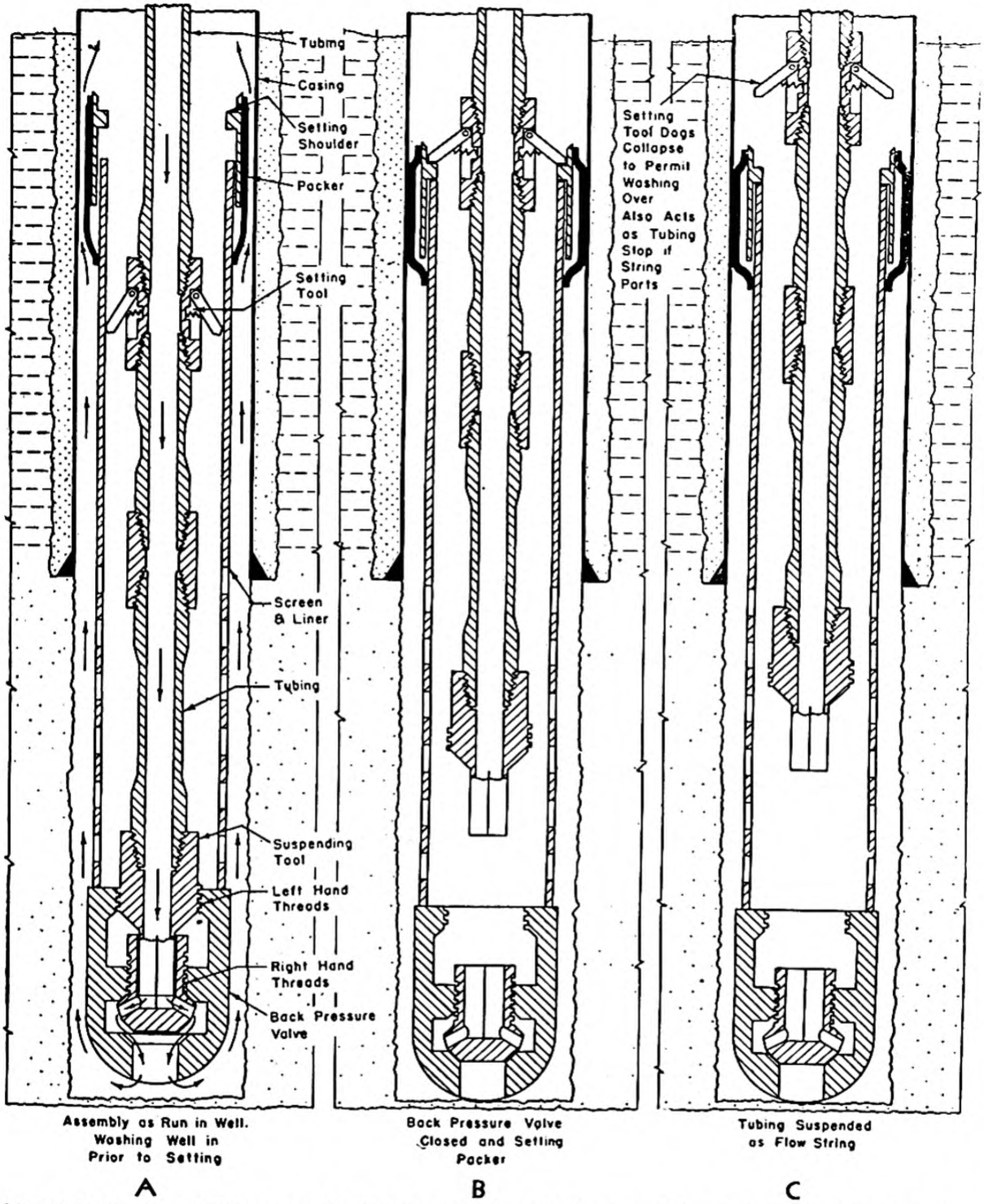
(Courtesy of Security Engineering Co., Inc.)
FIG. 246.—Liner hanger.

Short liners may rest on bottom without the protection of an oil string, no effort being made to suspend them from the casing. A column of casing is landed above the producing horizon and a smaller hole drilled through the reservoir rock. Clay and detrital material are circulated out of the hole, "spotting" clear water opposite the producing formation. The liner is then lowered until it rests on bottom with the aid of a J or I slot in its upper end, engaged by a pin in a special fitting in the lower end of the suspending tubing. Turning the tubing slightly then releases it from the liner so that the tubing can be withdrawn to the surface, leaving the liner on bottom.

When the liner must be suspended from the casing and the annular space packed off, more elaborate devices are necessary. Figure 246 illustrates a typical liner hanger packer. The connection to the run-in string is made through a left-handed threaded joint. While lowering the liner on the suspending tubing, the slip-cage assembly is held in the retracted position by a retaining pin. To set the slips, the run-in string is lifted slightly and rotated about a half turn to the left. Friction of the spring against the casing holds the slip assembly in place while the retaining pin moves out of the locked position, thus freeing the slips so that when the string is lowered they will set. After the slips are set, the packing rings are expanded by allowing the weight of the run-in string to bear down against the slips before the back-off thread is disengaged.[24]

Figure 247 presents sketches illustrating the method of operation of a common type of liner packer with provision for washing out the annular space before the liner is set on bottom. With the liner suspended a little off bottom, accumulated clay and detrital material are thoroughly washed from the annular space by continued circulation, as indicated in Fig. 247A. The liner is then set on bottom and the suspending tubing released from the liner by turning to the right until the left-hand thread

in the suspending tool are disengaged. The tubing is raised until the expanding lugs on the setting tool are disengaged. The tubing is raised



(*After J. R. Suman in "Elements of the Petroleum Industry," Courtesy of Am. Inst. Mining Met. Eng.*)

Fig. 247.—Method of setting liner packer.

until the expanding lugs on the setting tool mounted on the tubing engage the top of the packer. The weight of the tubing is then allowed to bear down on the packer, collapsing it and expanding the packer rings against

the casing, as indicated in Fig. 247*B*. The tubing may then be withdrawn to the surface, as shown in Fig. 247*C*, leaving the liner in the well. With another type of packer and suspension mechanism, the liner is suspended from its upper end. After washing, turning the suspension tubing to the right trips the packer mechanism so that the setting tool presses down on top of the packer under the influence of the weight of the tubing above and expands the packer rings. The tubing and tripping mechanism may then be removed. Still other types of packers are designed to be expanded by rotating the tubing on which they are suspended.

Plugging the Bottom.—To prevent sand and water from entering the space within the oil string, it is customary to plug the lower end of it with

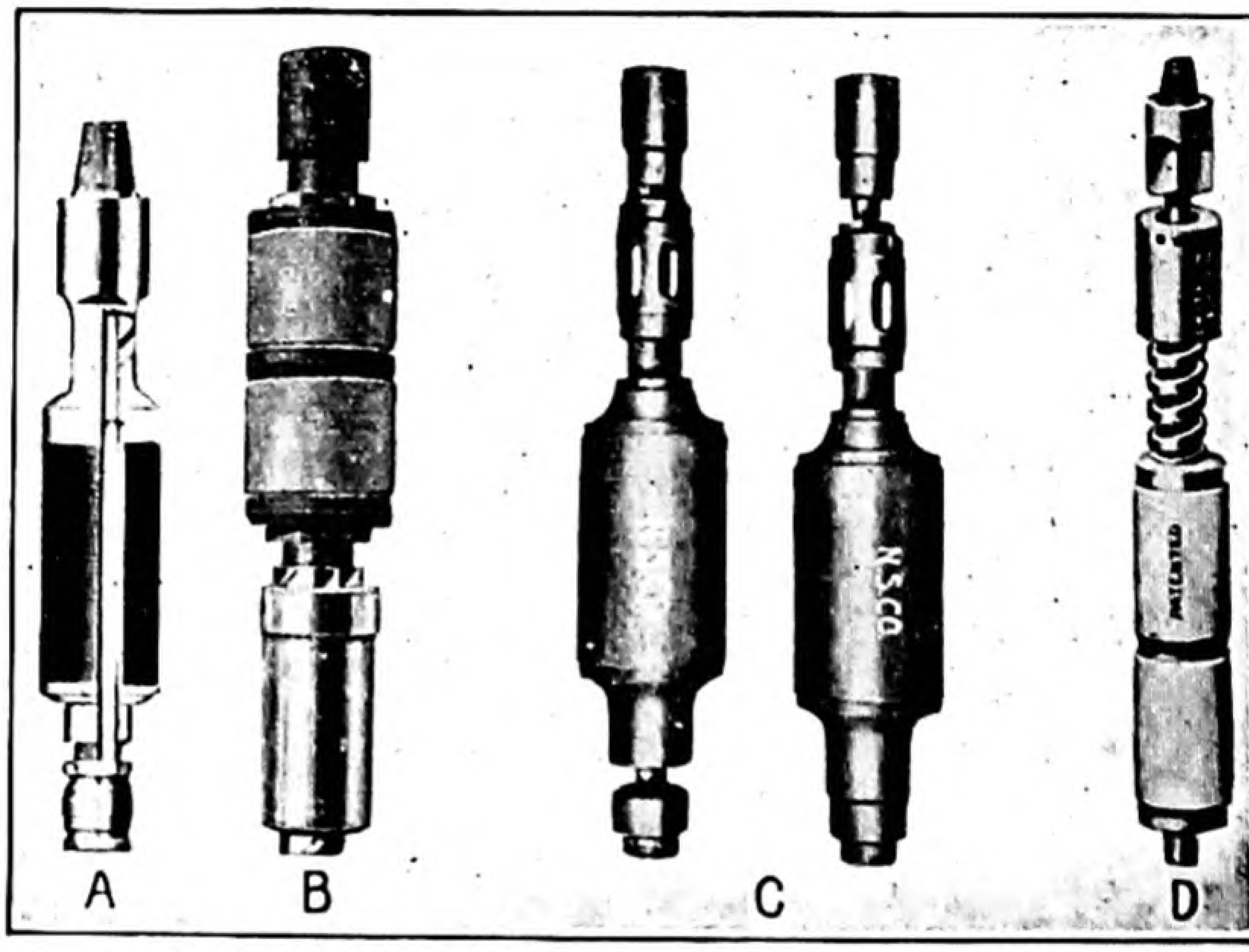


FIG. 248.—Types of swabs. *A*, "Ideal" swab; *B*, Beam swab with unloader; *C*, Kline swab with plunger valve; *D*, Heeter's swab.

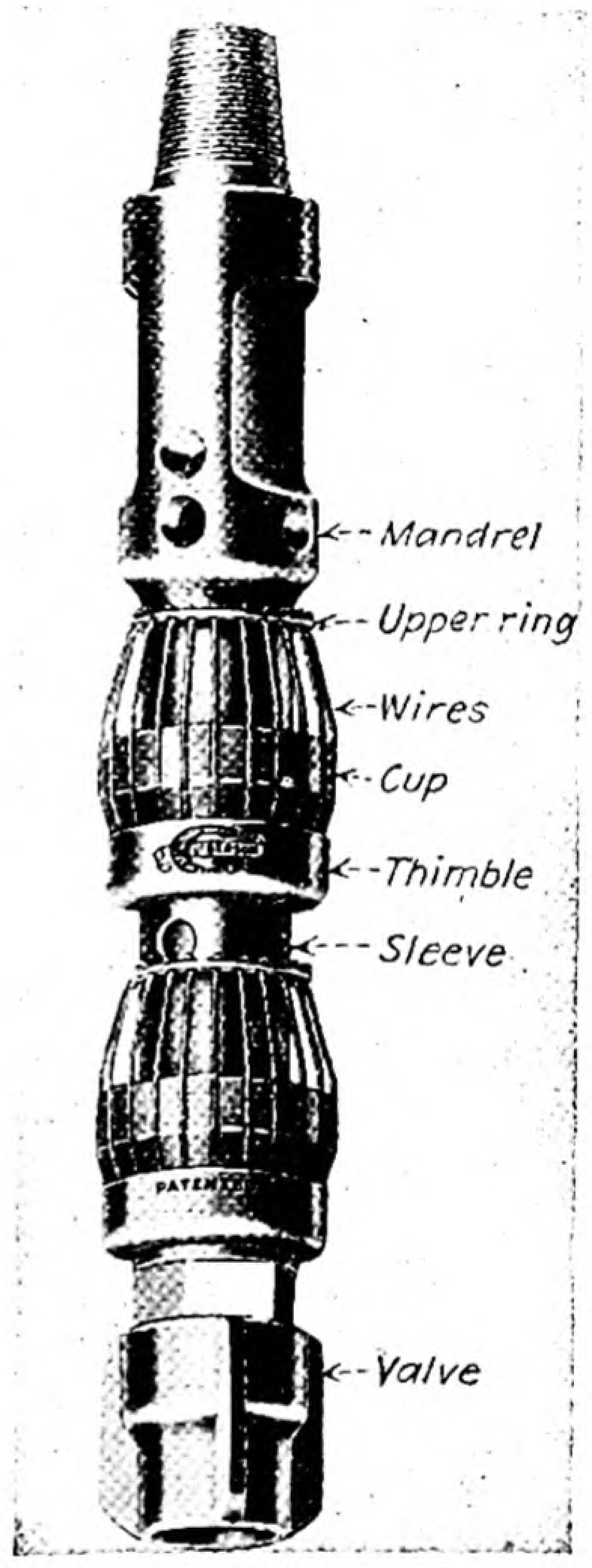
a wooden, lead or cast-iron "heaving plug" or "limit plug." The various forms of plugs have already been adequately described in connection with cementing operations in Chap. XII.

Swabbing to Clear Perforations, Screens and Sand Pores.—The method adopted for placing the oil string or liner often leaves the perforations or screens clogged with clay or sand. It often happens also, unless the mud can be washed from the well by circulating clear water, that the walls will be plastered with clay and the rock pores clogged so that oil does not flow freely. In such cases the application of a swab will usually remedy the condition by drawing the mud into the casing so that it can be bailed out.

The swab (see Fig. 248) is a rubber-faced hollow cylinder with a pin joint at the upper end to connect with the drilling tools, and on the lower end is placed a check valve opening upward. The steel body of the tool is constructed of perforated tubing, the fluid having access to the

inside of the rubber cylinder through the perforations. The rubber sleeve can be expanded to fit snugly within the casing by compressing it longitudinally. This is accomplished by tightening the pipe coupling on the lower end against the metal ring which supports the rubber cylinder.

The swab is lowered slowly to the bottom of the well on the drilling cable, the well fluid lifting the check valve, passing up through the inner tube and into the space above, through holes drilled in the wrench squares. On reaching bottom, power is applied and the swab is rapidly pulled out of the well. The check valve prevents the well fluid from again passing through the swab, and it is forced ahead of the latter to the surface. The rubber cylinder is only slightly smaller than the inner diameter of the casing, and when the fluid pressure is brought to bear against the inner surface of the rubber (through the perforated supporting pipe), it is expanded until it presses firmly against the casing, effectively preventing leakage of fluid around the cylinder. Because of the small clearance between the swab and the casing, it is important that the inner surface of the casing be free from indentations and blisters; otherwise the rubber cylinder will be rapidly destroyed and there will be considerable resistance to movement.



(*Courtesy of Guiberson Corp.*)
FIG. 249.—Guiberson basket-type swab.

Figure 249 illustrates a popular type of swab which comprises a flexible basket construction instead of the usual rubber cylinder. The hollow supporting mandrel contains an upward-opening valve. The bottom of each flexible swabbing element, with its supporting basket of heavy wire, is fastened rigidly to the mandrel, but the upper part is free to expand or contract as pressure conditions dictate. When the swab is lowered through fluid, the valve opens and upward pressure compresses the baskets. When the swab is lifted, fluid pressure closes the valve and expands the baskets so that they press firmly against the inner surface of the casing or tubing through which they are operated.

In addition to providing a means of rapidly and effectively removing all fluid from the well, application of the swab creates a reduced pressure within the casing, which draws oil, loose sand and clay through the

perforations. The perforations and screens are thus cleared of obstructions and a flow of oil into the well is established. After the swab has been removed, the bailer is lowered to remove sand and mud which have been drawn through the perforations.

It is important in operating the swab not to trap more fluid above it than the power is able to lift or than the swab is designed to support. An improved type of swab is equipped with a valve combining the principles of a vertical check valve and a pop safety valve, which automatically releases any excess fluid beyond that for which the valve is set.

USE OF EXPLOSIVES IN WELL COMPLETION

The use of explosives in stimulating production of oil and gas from wells is common practice in regions where the producing strata are limestones or well-indurated sandstones of relatively low permeability. The objective is to increase the well diameter through the reservoir rock and increase permeability and open drainage channels, developing fractures through the producing formation about the wall of the well. Each of these results tends to increase production efficiency.

Types of Explosives Used.—Three different types of explosives are used in well shooting: (1) liquid nitroglycerin, (2) 100 per cent gelatin explosive and (3) various grades of dynamite. Of these, nitroglycerin is preferred by most producers and is used for a large percentage of oil-field shooting jobs, though thoroughly satisfactory results are had with blasting gelatin when it is properly used. The less powerful dynamites are seldom used in shooting for production. Nitroglycerin, $4C_3H_5(NO_3)_3$, is prepared by treating glycerin with nitric acid. At normal atmospheric temperatures it is an unstable liquid which, when subjected to a sharp shock, almost instantly decomposes to form gaseous products:

$$4C_3H_5(NO_3)_3 \rightarrow 12CO_2 + 10H_2O + 6N_2 + O_2$$

Containing a surplus of oxygen, it requires no atmospheric oxygen to complete the explosion. Each pound of nitroglycerin yields, on explosion, 157.7 cu. ft. of permanent gases, developing a terrific disruptive force when confined, and generating a temperature of 6280°F. Propagation of the reaction through the explosive is at the rate of 23,600 ft. per sec. Ordinary nitroglycerin freezes at 45°F. and presents definite hazards in thawing. An improved type of liquid explosive, much like nitroglycerin but freezing at −40°F. and therefore much safer to handle, is nitroglycol, $(CH_2ONO_2)_2$. This is prepared by mixing distilled glycerin oil and ethylene glycol and/or polymerized glycerin in proper proportions before nitration. On explosion, this substance decomposes as follows:[70,72]

$$(CH_2ONO_2)_2 \rightarrow 2CO_2 + 2H_2O + N_2$$

Placing and Preparing the Shot.—Liquid explosives used in well shooting are charged into long cylindrical containers called "torpedoes" or "shells." From 5 to 300 qt. of the explosive may be used in a single charge, the amount depending upon the nature and thickness of the formation to be shot. The shells must be at least 1 in. smaller in diameter than the inside diameter of the casing in which they are to be lowered and vary in length depending upon the capacity desired. Capacities are often

10, 20 or 30 qt., and as many shells will be used as are necessary to make up the total quantity of explosive required. Shells are placed end to end through the interval to be shot. On top of the explosive, a detonating device is placed, and the charge tamped or "stemmed" with water, sand, gravel or cement. After the explosion, the resulting gases are confined by the stemming so that their disruptive force is exerted against the wall of the well, shattering the wall rocks and creating fractures that extend for some distance outward through the surrounding formation.

The explosive should be concentrated in large-diameter shells in the lower half or two-thirds of the interval to be shot. Usually this is at or near the bottom of the well. If not, the explosive shells should be supported on a suitable bridge or anchor of small pipe extending to bottom and the hole filled with water to the point of support. The amount of explosive to be used will depend upon the thickness and character of the formation to be shattered. In this connection, consideration must be given to the frangibility and elasticity of the reservoir rock. There is no precise means of determining the amount of explosive that will produce the best result under a given set of conditions, but it is known that satisfactory results are often secured in highly frangible rocks like most limestones, with 4 to 6 qt. of explosive per foot of interval to be fractured. Dolomitic rocks and well-cemented sandstones are less frangible and require more explosive than limestone, or as much as 8 to 10 qt. per ft. of hole through the interval to be shot. Small-diameter holes that will not accommodate as much explosive as desired may be sprung with a small preliminary shot to create enough space for the quantity of explosive needed for a fracturing shot. The enlarged hole may then be filled with explosive, generally blasting gelatin in this case, though liquid explosive may be placed in the well cavity with the aid of a dump bailer.

Earlier practice in stemming the shot involved filling the well with water for some distance above the top of the explosive. The inertia of this column of water confines the force of the explosion to a considerable extent, so that much of its energy is expended laterally rather than up the hole. A better practice is to use solid stemming, such as wet sand or fine gravel that is shoveled down the well on top of a "bridge" placed just above the explosive and its detonating device. Some operators prefer to use a little quick-setting cement, such as gypsum cement, just above the bridge. Solid stemming is more efficient, but is more costly to remove after the shot is fired, than liquid stemming. The more completely the explosive is confined by stemming, and the greater the volumetric density of the explosive, the more far-reaching will be the lateral fracturing effect. Theoretical analysis indicates that the fracturing radius varies as the cube root of the size of the charge for static conditions and as the first power of the size of the charge when the time rate at which the pressure is applied is considered.[68,70]

Detonating the Explosive.—The explosive is detonated by either of several methods: (1) A firing device mounted in the top of the uppermost shell, equipped with a percussion cap and a firing pin, upon which a go-devil (a short iron bar) is dropped from the surface (see Fig. 250). (2) A "jack squib," consisting of a metal tube containing dynamite or 100 per cent blasting gelatin, primed with a detonating cap and fuse and weighted with sand. The fuse is ignited and the squib dropped from the surface on the charge (see Fig. 251*A*). (3) A "bumper squib," which consists of a short tube filled with nitroglycerin and equipped with a firing head and pin and a percussion cap. A 4-ft. length of 2-in. pipe is attached to the top of the squib in such a way that the firing head is exposed in the lower end of it (see Fig. 251*B*). The wire on which the squib is lowered into position passes freely through the bail on the upper end of the pipe, and a heavy weight—such as a sash weight—is fastened on the end of the line below the bail. As the squib is lowered, the sash weight supports the bail but, when the squib comes to rest on the charge, release of tension in the line at the surface per-

mits the sash weight to descend, striking the firing head and detonating the charge. (4) An "electric squib," containing dynamite or 100 per cent gelatin, weighted with sand and primed with an electric blasting cap attached to a duplex firing cable, which serves to lower the squib into the well and as a means of transmitting electric current from a blasting machine or a power circuit at the surface. (5) A time bomb mounted in a moisture- and pressure-proof case, containing a charge of dynamite, two blasting caps and electric igniters, a battery of dry cells which furnishes electric current and a control timepiece.[71]

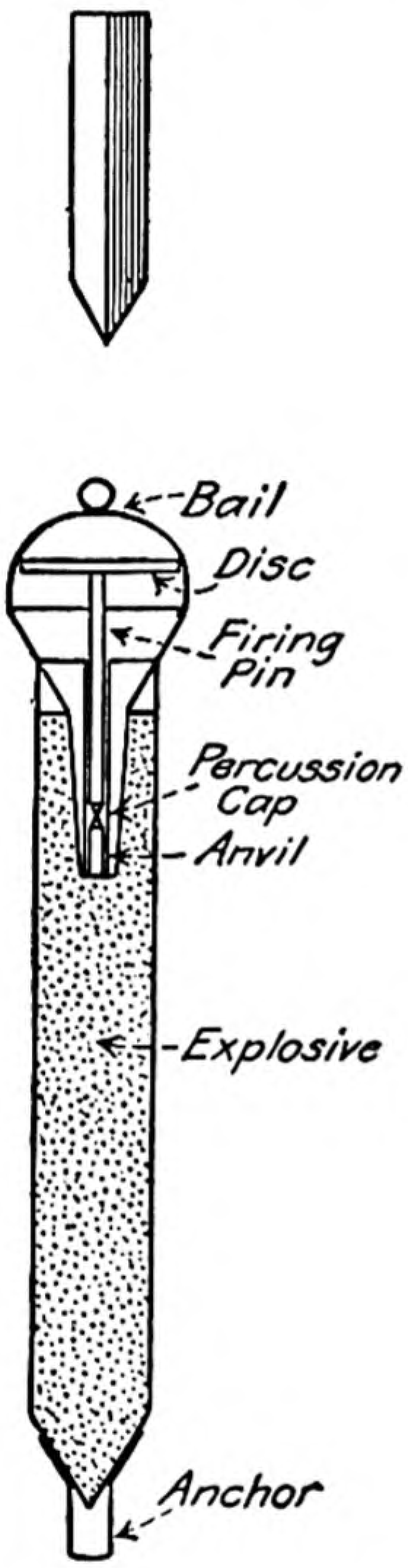
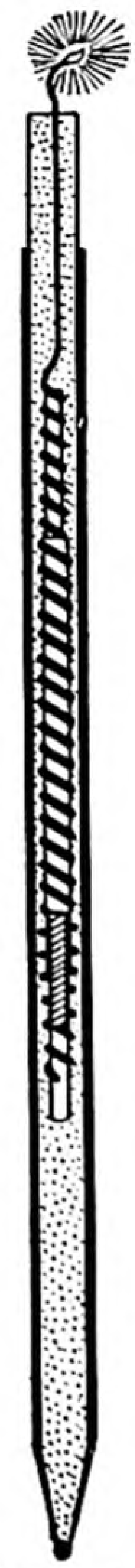
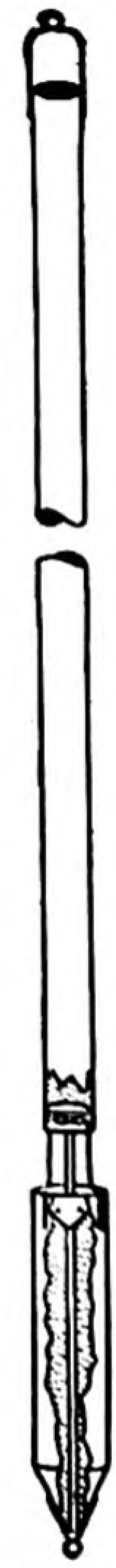


FIG. 250.—Impact detonating device for use with "go-devil."

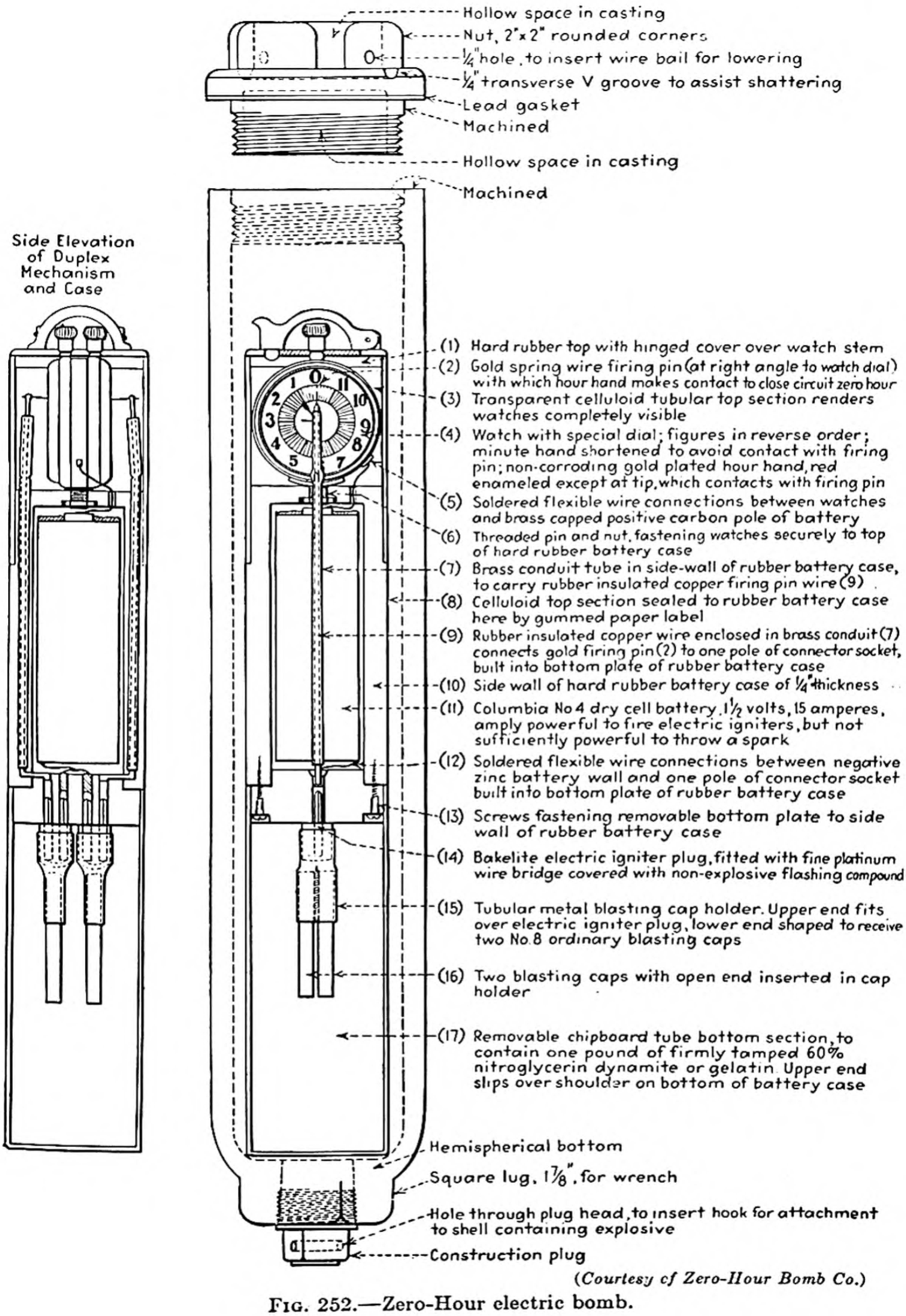


(*After W. H. Jeffery.*)
FIG. 251*A*.—Jack squib.



(*After W. H. Jeffery.*)
FIG. 251*B*.—Bumper squib.

Go-devil firing and squibs may be used only when the charge is fluid stemmed. For solid stemming, preferably employed, or where the walls of the well display caving tendencies, the electric squib or time bomb must be used. For dependability and security, the time bomb is preferred to other detonating devices by most operators. Figure 252 illustrates a widely used type of time bomb. The watch may be set to close an electrical contact which fires the charge at any predetermined time with a safety interval of from 1 to 22 hr. A duplex bomb, designed for greater certainty in operation, is equipped with a double set of caps and igniters and two synchronized timepieces. If necessary, the several parts of this bomb may be enclosed



(*Courtesy of Zero-Hour Bomb Co.*)

Fig. 252.—Zero-Hour electric bomb.

within a tube only $1\frac{1}{2}$ in. in diameter. A device of this character embodies most of the advantages of electric detonation without the added complexity and expense of providing an electric circuit extending to the surface.

Well-shooting Technic.—Because of the hazards presented, the oil producer finds it advantageous to employ a service organization specializing in this type of work to conduct his well-shooting operations. This organization is equipped to furnish the explosive and transport it to the well, and provides such special equipment as is necessary and the services of a skilled well shooter who takes full charge of the well and fires the shot. Such work is undertaken by the service organization on a contract basis, the cost to the operator being $3 per quart of explosive in some regions of the United States.

Because of the sensitive character of nitroglycerin, every precaution should be taken in handling it to prevent an accidental explosion. It should not be transported in leaky cans. Unnecessary friction and jarring of the containers should be avoided. The corks and empty cans should be destroyed. Special care should be taken in placing the shot so that it does not damage the casing and other well equipment, or fracture the cap rock overlying the reservoir rock so that top water is admitted to the well or oil and gas allowed to escape to overlying formations. If the shot is stemmed with water, the casing should be lifted above the surface of the water, or the well should be filled with water. Accurate depth measurements are necessary in order to place the charge in the proper interval in the well. A dummy torpedo should be lowered to bottom before running the explosive shells, to be certain that there are no obstructions that may hang up a torpedo in the well before it reaches its intended position.

The steel torpedo line and reel and the reel brakes—used in lowering the shells into the well—should be carefully inspected to be certain that they are in good operating condition before lowering the explosive. The torpedo line should be "flagged" or marked 100 ft. or so above its lower end, and, on drawing the line out of the well after lowering a shell, hoisting speed should be reduced as the lower end nears the surface. Shells are supported on the lower end of the torpedo line by an open hook which engages a bail on the upper end of the torpedo. This hook is supposed to disengage itself from the bail when the torpedo is placed on bottom but may fail to do so, in which event, the torpedo may be hoisted back to the surface when the torpedo line is withdrawn and, if it should strike the torpedo line pulley or reel over the well, a disastrous explosion might result. The shells are usually made of tinned sheet metal, and at times the magnetic drag of the shell and the torpedo line on the steel casing is so great that trouble is experienced in getting the shells to bottom. Insulated or nonmagnetic torpedo shells of brass, aluminum or plastic material such as bakelite are free of this difficulty and are sometimes used for this reason.

Nitroglycerin free from excess acid will not explode at temperatures normally encountered in oil wells, but slow decomposition results at temperatures above 140°F., and in deep wells in some fields where ground temperatures are high, the explosive apparently undergoes decomposition and explodes spontaneously after a period of from 2 to 100 hr. Under such conditions, shots may be allowed to explode spontaneously in this way, without the aid of detonating devices, but a time bomb is much more dependable. Excavating solid stemming above nitroglycerin shells that have failed to explode is a hazardous operation.

Effects of the Shot.—Following the explosion, violent ejection of oil, gas, water and rock particles from the stemming and from the walls of the well will often result if liquid stemming is used. Vibration of the casing gives warning many seconds before the rush of gas reaches the surface and before the sound is heard. In anticipation of a shower of water, oil and debris, the shooter should promptly seek a place of safety. If solid stemming is employed in sufficient amount, it will wedge in the well

above the bridge and there will usually be but little surface indication of the shot. Perhaps a slight bump will be felt if the shot is not too deep, and a small flow of gas may be observed. Sometimes the bump is felt more distinctly a few hundred feet away from the well than at the casing head. It is usually impossible to determine the full effects of a shot, but it is generally believed that the maximum force of the explosion is exerted at the bottom of the interval in which the explosive is placed, shattering the walls of the well and forming a pear-shaped cavity. The shock is reflected from the bottom back toward the surface through the surrounding rocks, at an angle from the axis of the well, forming crevices in the surrounding reservoir rock that many authorities believe extend outward and upward for many feet from the wall of the well, cutting across bedding planes and opening drainage channels. Elasticity of the overburden may permit momentary upward displacement of strata, temporarily creating openings along bedding planes of the sedimentary strata composing the reservoir rock. After cleaning out the detrital material from the well, a substantial flow of oil and gas will often follow, and this may be sustained for several weeks or months. Shot cavities in hard elastic rocks are frequently several feet in diameter, as determined by caliper surveys or by filling them with measured amounts of gravel.

ACID TREATMENT OF WELLS

Completion of wells in fields producing from limestone or dolomite reservoir rocks frequently involves treatment with hydrochloric acid. Such reservoir rocks often have low permeability or lack continuous porosity and do not develop commercial rates of production until shot with explosives or treated with acid. The acid, forced outward through the walls of the well under hydrostatic or pump pressure, enters the drainage channels tributary to the well, dissolves the exposed limestone surfaces and increases the permeability of the formation surrounding the well.

Hydrochloric acid used for this purpose may be varied in its characteristics to suit the conditions presented. For the average limestone, a 15 per cent acid, by weight, is used in quantities ranging from 1,000 to 10,000 gal. An inhibitor is added to restrict its chemical action on steel casing, tubing and other well equipment with which it comes into contact. For use on less soluble dolomitic limestones, an intensified acid is used, prepared by adding a reagent which hastens solution by catalytic action. Surface-tension-reducing agents are sometimes added to the acid to facilitate its penetration into less permeable formations. Non-emulsifying agents prevent formation of highly viscous, refractory emulsions that prove troublesome with some types of crude petroleum. For use in unusually reactive limestones, a retarding agent may be added to the acid to permit it to penetrate the formation for some distance before it is neutralized by chemical reaction.

In applying acid treatment to a well in process of first completion, when surrounding reservoir rocks are as yet undrained and field pressures are sufficient to support high fluid levels, the well is equipped with a column of tubing extending from the surface down to the bottom of the interval in which it is wished to apply the acid

Tubing-head connections are made so that oil or acid from near-by tanks may be forced down the tubing under pump pressure. The annular space between the tubing and the casing is closed by a casing head capable of withstanding pressure without leakage and valve-controlled side-outlet connections rigged to a near-by tank in which displaced oil may be gauged. A computation is made to determine the volume of the annular space between the tubing and the wall of the well in the interval to be treated. The volume of the tubing is also calculated. If the interval to be treated is some distance above bottom, the lower part of the well, up to the level of the lower end of the tubing, is filled with a "blanket" solution of calcium chloride. This is heavier than the acid to be used and does not react with it. Its function is to prevent access of the acid to the interval below the lower end of the tubing. Crude oil is then pumped down the tubing, returning to the surface through the annular space until the well is filled with it from the top of the column of blanket solution to the surface. Acid is then pumped down the tubing, displacing oil from the side outlet of the casing head, in volume equivalent to that of the annular space through the interval to be treated plus the volume of the tubing. The valve on the side outlet of the casing head is then closed so that no more oil may escape from the well. Pump pressure is then applied to the column of acid in the tubing, forcing acid into the producing formation through the wall of the well. When the desired amount of acid has entered the tubing, oil is pumped down on top of it. The pumping is continued until all acid has been displaced from the tubing. Equilibrium pressure conditions are then maintained until the acid has had time to react fully with the limestone reservoir rock. The reaction produces carbon dioxide and calcium chloride solution, fluids which readily flow back into the well when an appropriate pressure differential is restored by releasing pressure at the well head and, if necessary, bailing or swabbing fluid from the well.[59,63]

Other methods of applying the acid have been devised for special conditions. In dealing with difficultly soluble, impermeable wall rocks, the acid may be applied through a gun which directs horizontal jets under high velocity against the wall of the well. Mechanical erosion thus aids the chemical effect of the acid in penetrating the wall rocks. In gas wells or where oil is not readily available, compressed gas may be used as the displacing fluid to confine the acid within its intended interval of application. Special study should be given to the formational interval to be treated, preferably based on inspection of cores taken in the course of drilling, to determine which portions of the interval will profit most by acid treatment. As a result of such studies, arrangements may be made to confine the acid to the less permeable strata. This may be accomplished with the aid of chemical sealing agents which temporarily seal the more permeable strata before the acid is applied. Thus, a thin solution of Dowell Jelly Seal can be forced under pump pressure into the more permeable strata. After about 30 min., this solution gels into a semisolid condition which seals the strata against invasion by acid. Before the Jelly Seal is placed in the well, it is inoculated with bacteria which within 24 to 36 hr. consume the solid parts of the gel so that it again assumes the liquid state and flows back into the well. Another Dowell reagent known as "Soap Seal" is used as an auxiliary chemical to reduce penetration of acid into water-bearing strata in the interval to be treated. Wherever this reagent comes into contact with salt water, an adherent precipitate is formed which seals the water-bearing strata against contact with the acid subsequently introduced. In the less soluble, "tighter" carbonate reservoir rocks, repeated application of acid in stages is sometimes more effective than a single treatment. Perhaps acid may not readily be forced into the wall rocks, even under high pressure, but the first application opens channels through which later applications may penetrate more deeply.

Acid is frequently applied to wells to stimulate production from partly depleted reservoir rocks by methods differing somewhat from those employed on wells at the

time of completion of the drilling process. Such work properly attaches to the production period rather than the development period. Further discussion of acid-treatment methods will be found in the companion volume of this work (see "Oil Field Exploitation," pages 376–379).

Successful acid treatment of wells requires equipment and skilled personnel not ordinarily in the employ of the oil producer. Accordingly, a service organization, equipped to deliver the acid in tank trucks and furnish equipment and skilled personnel to supervise its injection into the well, is ordinarily employed when acidation is necessary.

CONTROL OF HIGH-PRESSURE WELLS

On drilling into a stratum containing oil or gas under high pressure, precautions should be taken against loss of control which might result in

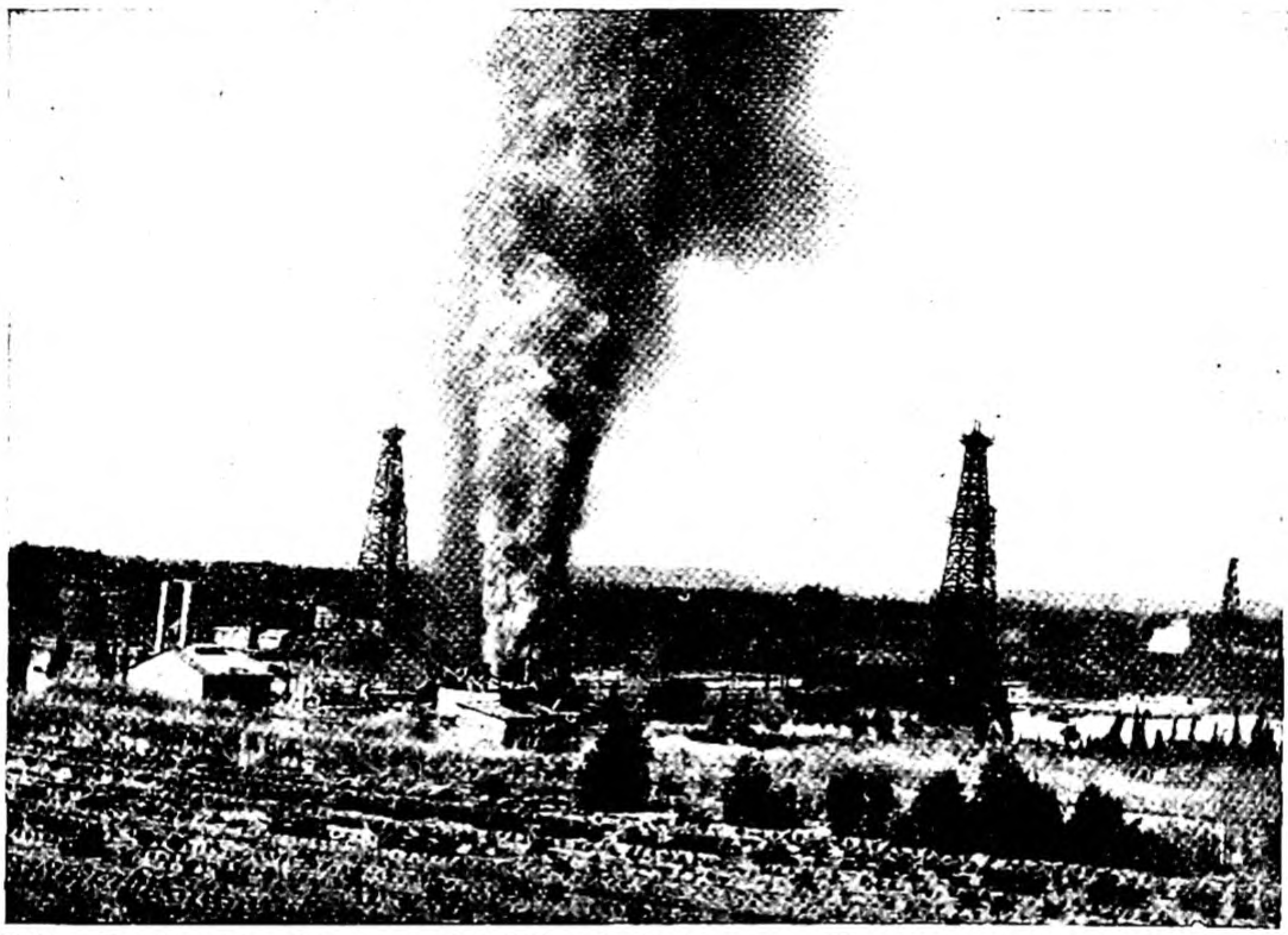


FIG. 253.—Destructive blowout of drilling fluid from a well on encountering a high-pressure gas zone, Santa Fe Springs field, Calif.

waste of oil and gas and serious damage to the well and its equipment as well as to surrounding property. Preventive measures are of two sorts: (1) the use of methods that prevent the destructive forces from becoming operative, and (2) the provision of safeguards that will make possible their control if they do become operative.

A high-pressure well out of control may prove exceedingly destructive. Violent ejection of the well fluid, perhaps accompanied by flows of sand, oil and gas, sometimes shatters the derrick, occasionally burying the drilling equipment (see Fig. 253). The drilling tools, rotary drill stem, and at times even the heavy casings, have been lifted bodily out of the well by the forces developed. Lack of control at such times often

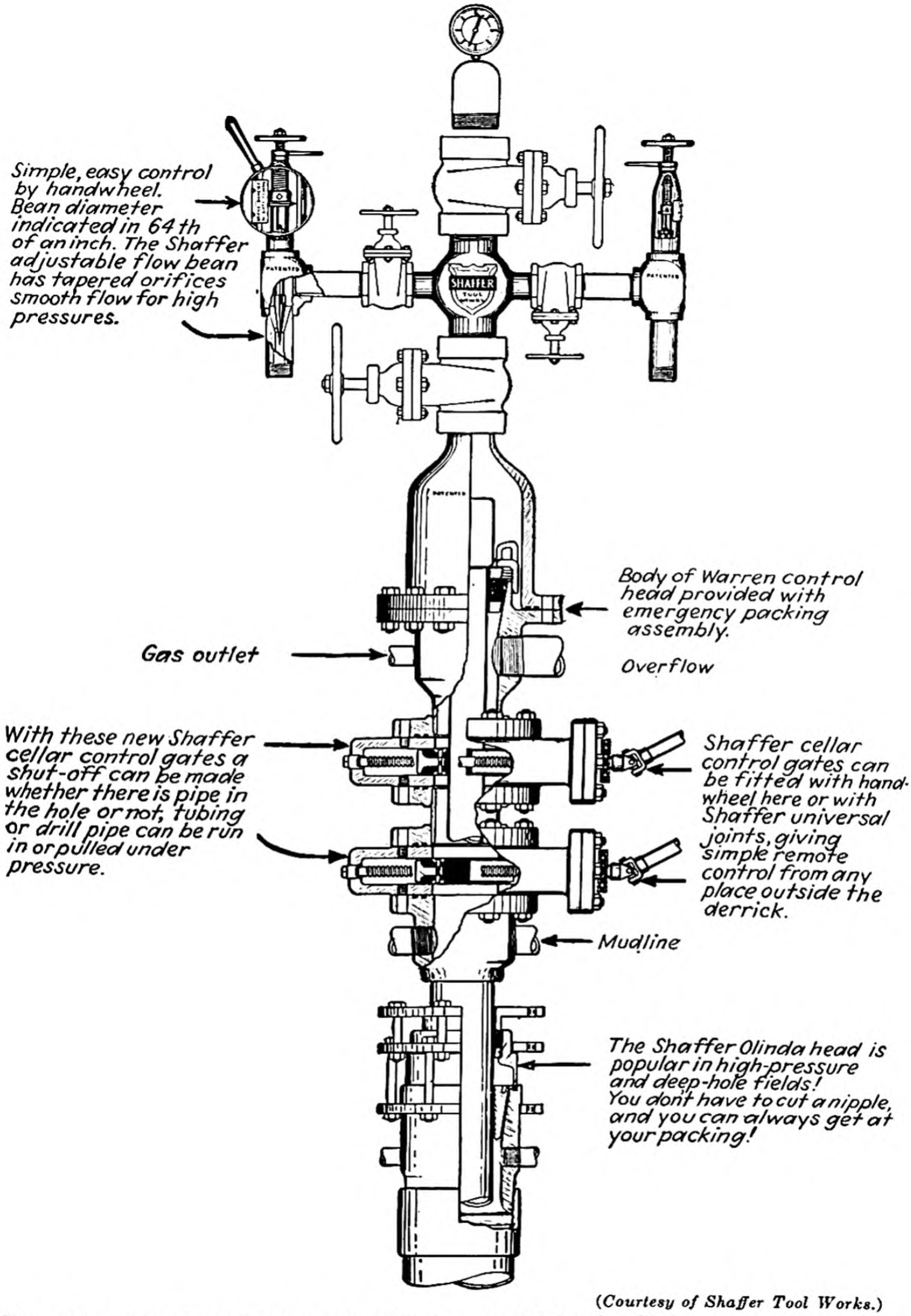
permits large quantities of sand to heave into the well, or the walls may cave or the casing collapse, necessitating redrilling or, in extreme cases, even abandonment of the well. Blowouts of high-pressure gas flowing around the outside of the well casings occasionally form craters which fill with water or oil and completely engulf the rig and its equipment. Oil jetted high into the air from the well is caught by the wind and sprayed over the surrounding terrain, carrying destruction to trees and crops and necessitating repainting of buildings. At such times, fire frequently adds to the destruction. A static spark resulting from friction of gas at the casing head; a spark caused by the striking of metal on metal, or rock on metal; or a flow of gas coming into contact with the boiler fires, the forge or other naked light—and the well and everything reached by the oil is converted into a mass of flame. Such conditions sometimes develop in so brief a space of time that they become a menace to the lives of the drillers. Once out of control, the flow of oil and gas may continue for days, weeks or even months, the damage wrought to the well equipment and difficulty of approach often making possible remedial measures ineffective.

High-pressure Well-control Equipment

When drilling in locations where high-pressure conditions may develop within the well, precautions should be taken in advance of actual need, that will permit of promptly shutting in the well at the casing head. The casing head, valves, fittings and other control devices used for this purpose should be of sufficient strength to withstand the maximum pressure to which they may be subjected. Formation pressures encountered in some of the recently drilled deep fields of the United States have exceeded 4,000 lb. per sq. in., and in order to provide an ample factor of safety some of the heavier well-head fittings are designed to withstand test pressures as great as 6,000 lb. per sq. in.

A well drilled in high-pressure territory will usually be equipped with a blowout preventer which can be quickly closed about the rotary drill pipe within the annular space between it and the casing. This is attached to the casing below the derrick floor so that drilling operations may be conducted through it. The Shaffer control gate, illustrated in Fig. 254, is designed to accomplish the same end.

It is important that suitable means be adopted to support the various strings of casing in the well and to close the annular spaces between telescoping strings by devices that will be capable of withstanding the high pressures to which they are often subjected. Frequently, too, they sustain a large part of the weight of the casing and must therefore be provided with adequate foundation supports. Figures 255, 257 and



(*Courtesy of Shaffer Tool Works.*)

FIG. 254.—Assembly of cellar control gates, special heads, Christmas-tree valves and fittings and adjustable-flow beans.

258 illustrate a variety of different types of control casing heads designed to accomplish these purposes.

After completing the drilling of a high-pressure well, and before bringing it in, it is customarily equipped with suitable valve equipment above the casing head to control flow of oil and gas from the well during the subsequent period of natural flow. An assemblage of valves designed for this purpose is called a "Christmas tree." Figures 254, 256 to 258 are illustrative of different representative Christmas-tree assemblies. Figure 257 presents a sketch of typical well-head fittings and valves used by a large company operating in the California fields. Five telescoping strings of casing are used in this particular installation, in addition to a column

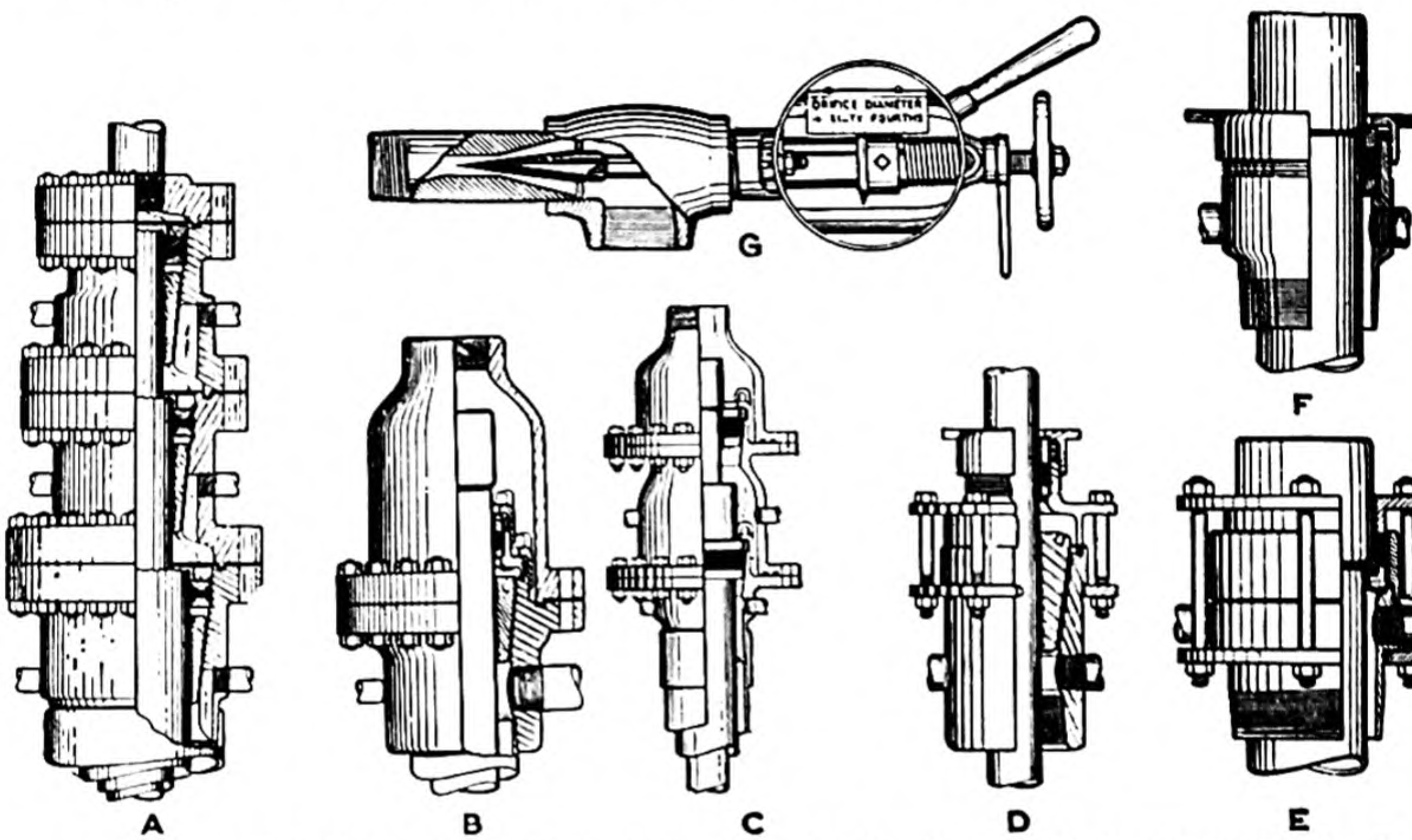
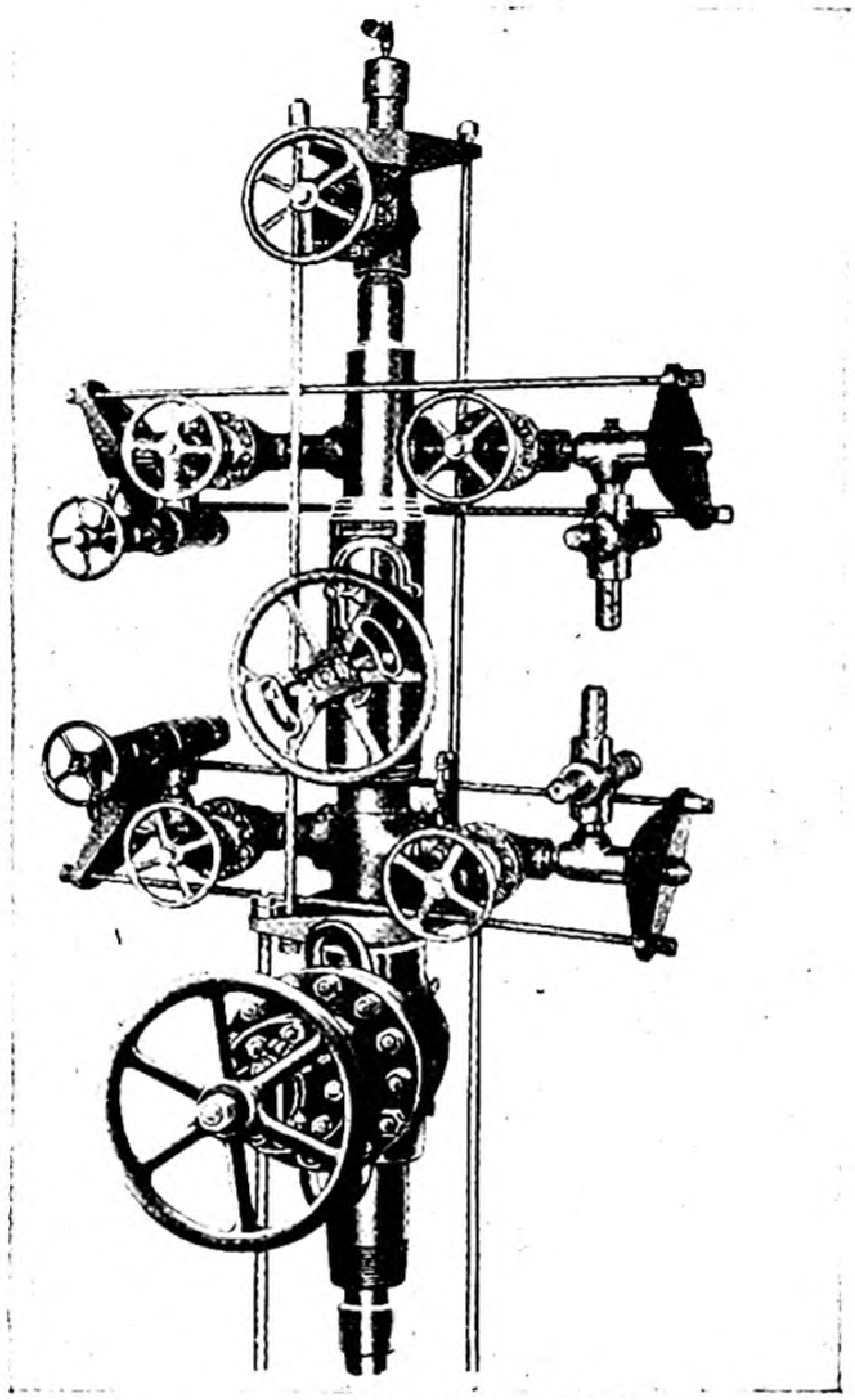


FIG. 255.—Flow bean and various types of casing heads manufactured by Shaffer Tool Works. *A*, spool-type head; *B*, Warren-Olinda head; *C*, Warren double-cap head; *D*, Olinda head; *E*, Western head; *F*, Athens head; *G*, Shaffer adjustable-flow bean.

of flow tubing. The assemblage of valves and fittings within the cellar shows the means adopted for closing the annular spaces between strings and preventing flow of fluids between. High-pressure valves and connecting nipples permit of venting pressures between any two columns of pipe when necessary. The Christmas-tree assembly above the derrick floor is similar to that pictured in Fig. 258. A special head closes the space between the flow tubing and the inner string of casing. Side outlets from this head permit of drainage of casing-head gas if desired. A pressure gauge on one of these flow lines indicates the casing-head pressure. Immediately above the head is the master gate. This is normally left open, being closed only in an emergency or when necessary to replace one of the upper control valves. A high-pressure forged-steel cross connects immediately above the master gate, the upper and two side

outlets of the cross being equipped with high-pressure control gates. Flow of oil and the associated gas is ordinarily through either or both of the side outlets of the cross. The upper valve serves as an additional control at such times as it may be necessary to allow the well to blow, or to permit excess oil and gas, beyond what can be taken care of by the side outlets, to escape. In the case of exceedingly high pressures it may

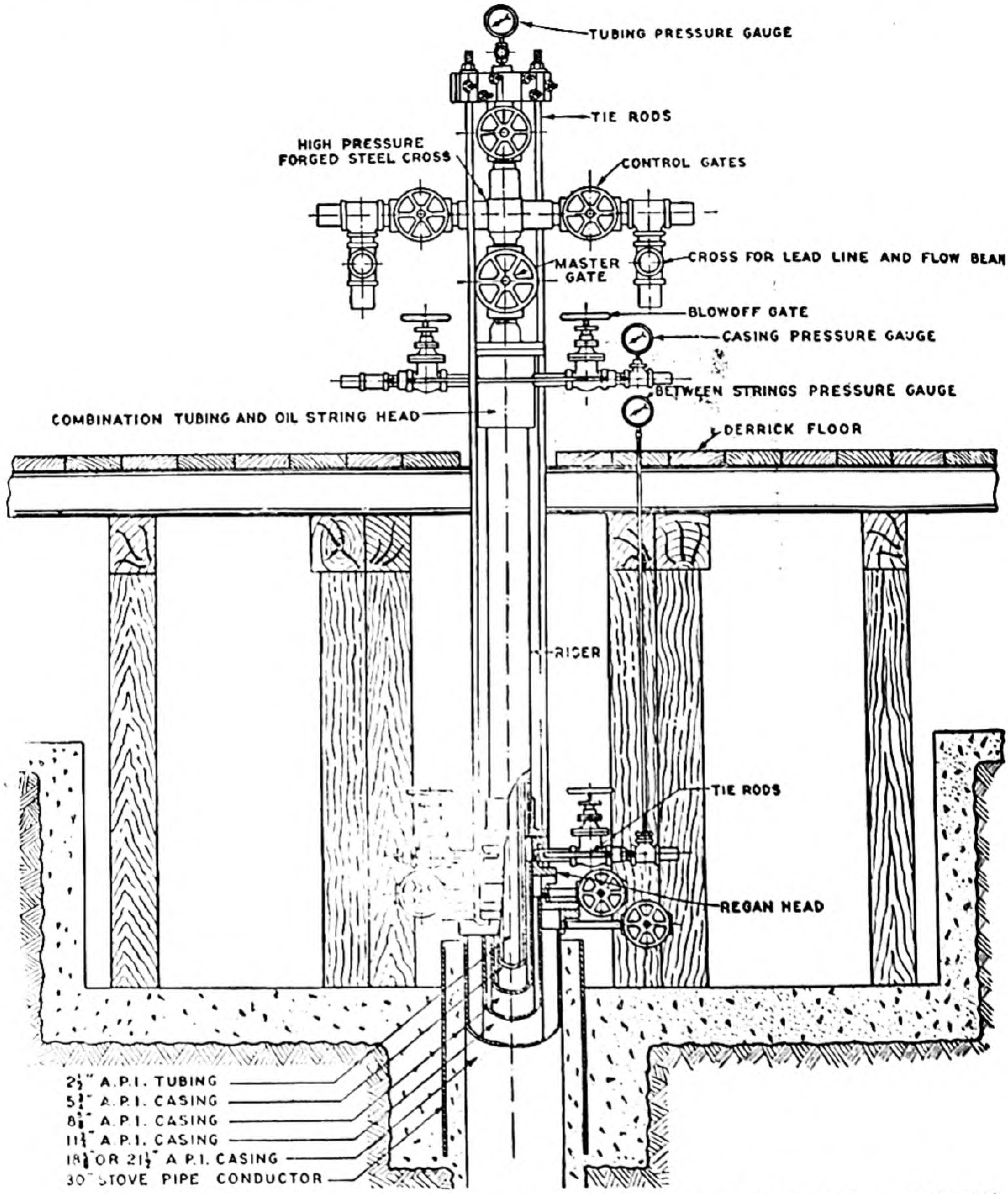


(*Courtesy of Hughes Tool Co.*)

FIG. 256.—Hughes Christmas-tree hookup of double flow lines, Brown retractor-head master valve, flow-line valves and Hughes flow beans.

be unsafe to shut in the well completely. A pressure gauge on the upper outlet indicates the tubing-head pressure. The side outlets from the forged cross are equipped with swing connections and dead-end nipples which cushion the valves and fittings against vibration and sand scouring, resulting from sudden changes in direction of flow. The scouring effect of sand carried by the oil may necessitate frequent replacement of valve parts and fittings. In each "lead line," a "flow bean" may be placed. This is nothing more than a constriction in the line provided for

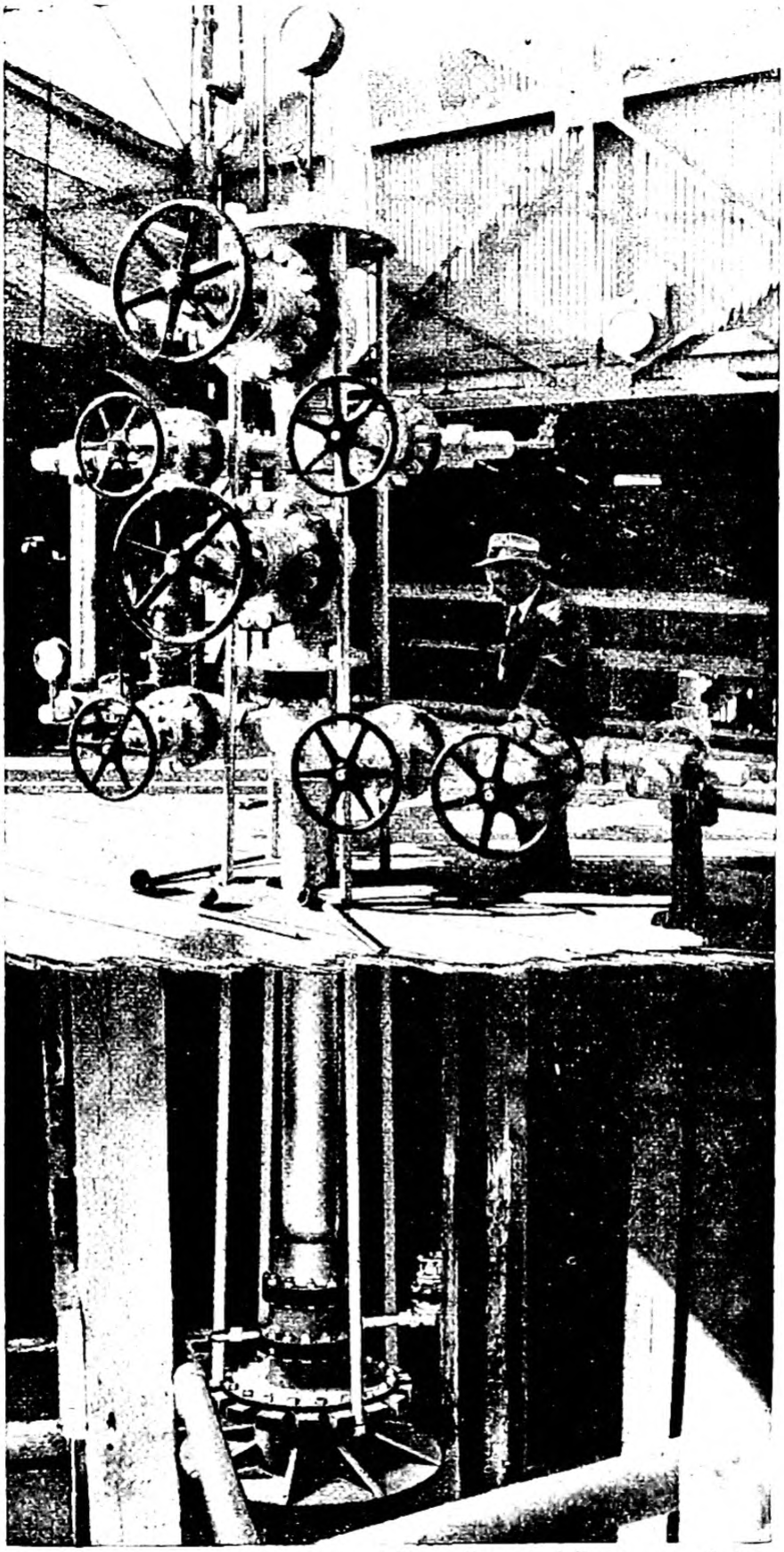
the purpose of restricting flow or maintaining any desired amount of back pressure on the well. The flow bean may be simply a block of metal supported in the path of flow by suitable fittings and having a small hole bored longitudinally through it. Apertures as small as 1/8 or 1/4 in.



(*After T. E. Swigart in Am. Petroleum Inst., Bull. 202.*)

FIG. 257.—Sketch of typical well-head fittings used on a high-pressure well in the Ventura field, Calif.

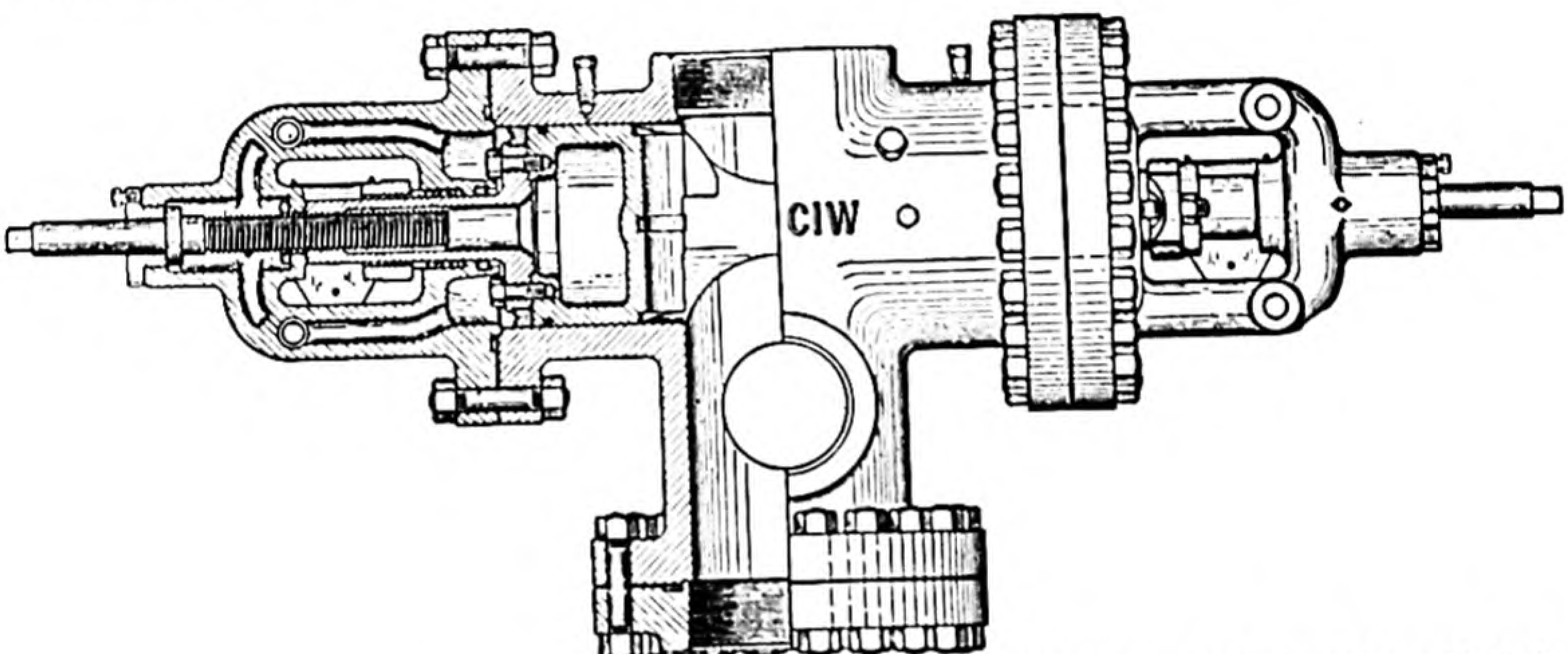
may be used when a considerable back pressure is required on a high-pressure well. A preferred type of flow bean is one in which restriction of flow is accomplished by means of a needle valve permitting close adjustment and variation of the size of aperture (see Fig. 255*G*).



(*Courtesy of Regan Forge and Engineering Co.*)

FIG. 258.—Casing-head and Christmas-tree fittings: a high-pressure installation in the Kettleman Hills field, Calif.

The Control Casing Head.—For use on wells which are expected to encounter high pressures, drilled with cable tools, a control casing head is often employed. This consists of a heavy casting in the form of a four-way tee which screws on the top of the working string of casing, the space between this and any larger string that may be in the well being closed with a packing ring screwed into the larger casing head. A special cylindrical valve, operated by a stem extending through a stuffing box in one of the side outlets, may be adjusted by a quarter turn to close either the top or bottom outlet of the tee, the side outlet being always open. A groove cut in the valve, large enough to admit the drilling cable, permits it to close when the drilling tools or bailer are in the well, without injury to the cable or sand line. By providing a 20-ft. extension of the valve stem, the valve may be manipulated from outside of the derrick. With the valve turned so that both upper and lower outlets of the tee are open, drilling operations may be conducted without interference. In the event of a sudden flow of fluid from the well, with the tools either in or out, by a quarter turn of the valve the well will be shut in, or the flow may be diverted through the side outlet and through a connecting lead line to a tank or sump.



(Courtesy of Cameron Iron Works.)

FIG. 259.—Cameron fluid-closing manual-opening blowout preventer.

The Blowout Preventer.—A device known as a "blowout preventer" is widely used on rotary-drilled wells to prevent the circulating fluid from being forced out of the hole when it is expected that high-pressure fluids will be encountered. This is a special form of casing head which is screwed on top of the last string of casing landed, or cemented in the well. It is equipped with a pair of sliding gates which close about the rotary drill stem and pack off the space between it and the well casing (see Fig. 259). The side outlets provide a means of connecting 6-in. pipe with the space between the casing and the drill stem. A gate valve provides the necessary control of each outlet.[1] The gates are ordinarily kept open, but in the event of a threatened blowout are closed about the drill pipe, preventing further escape of the well fluid. Each gate is controlled by a separate stem operating through a threaded nut and stuffing box, such as are used on an ordinary gate-valve stem. An extension of the stem permits of operating the device from the outside of the derrick. A steam-controlled type of blowout preventer requires only the opening of a valve on a connecting pipe at a safe point outside the derrick to close the annular space about the drill pipe. A back-pressure valve in the drill stem prevents mud from blowing out through the stem, and with a blowout preventer to pack off the space between the stem and the casing the well is securely shut in until the pressure can be killed with mud, or until provision can be made for taking care of the flow. If cable tools are employed, the

blowout preventer can be used effectively in packing off the space between two strings of casing. In connection with a gate valve or control casing head on the inner casing, through the open gate of which the cable tools may be operated, ample security against blowouts is afforded.

Oil Savers.—Various devices known as "oil savers" are available for closing in the top of an ordinary casing head in such a way as largely to prevent the escape of fluid under pressure about the well mouth, yet permitting free movement of the drilling cable. These are of two general types: (1) one in which the cable works through a gland stuffed with hydraulic packing and (2) one in which the cable is enclosed within a long, polished working barrel passing through a suitable stuffing box. The latter is similar in principle to the circulating head described in connection with the standard circulating system of drilling (see page 196). The ordinary forms of oil savers are simply held in position in the casing head by set screws and are not absolutely secure against leakage if subjected to great pressures. They serve, however, to divert oil which may flow from the well while drilling is in process, through the side outlets of the casing head into the lead lines connecting with the storage tanks or sumps.

Control of High Pressure by the Use of Mud-laden Fluid

In controlling high-pressure gas, the best plan is to deal with the menace at its source and prevent the gas from entering the well. This can ordinarily be accomplished with the aid of mud-laden fluid. We have seen that the opportunity afforded to use mud-laden fluid in sealing off and controlling high-pressure sands is one of the principal advantages of the modern hydraulic rotary and standard circulating methods of drilling.

The effects and manner of application of mud-laden fluids in ordinary drilling practice have already been adequately described (see Chap. VIII), but descriptions of certain special applications of the mudding process in controlling high pressures have been reserved for the present chapter.

If the well is being drilled by rotary methods and high-pressure gas is encountered, the circulating fluid is at once thickened by the addition of clay to the mud pit, drilling being discontinued for a time, if necessary, to allow ample opportunity for the mud to seal the pores of the high-pressure stratum. Every precaution must be taken to avoid a blowout, or ejection of the fluid from the hole. The ability of the circulating fluid to resist the gas pressure and prevent its admission to the well depends chiefly upon the hydrostatic head developed. Ordinarily about 15 per cent heavier than water, each 100 ft. of mud-fluid pressure is equivalent to about 50 lb. per sq. in. This can be increased to as much as 61 lb. per sq. in. by addition of clay until the fluid has a density of 1.4. At a depth of 1,000 ft., the mud fluid may therefore exert a pressure of 610 lb. per sq. in. If a gas sand encountered at this depth is under a greater pressure, obviously gas will enter the well; and unless additional pressure is applied or the outlet from the well is closed, the fluid will be violently ejected. If there is danger of this, it may be necessary to resort to the use of ground barite or hematite instead of clay. With heavy

minerals such as these, fluid suspensions having a density more than twice that of water and developing static pressures of upward of 90 lb. per sq. in. per 100 ft. of depth can be prepared.

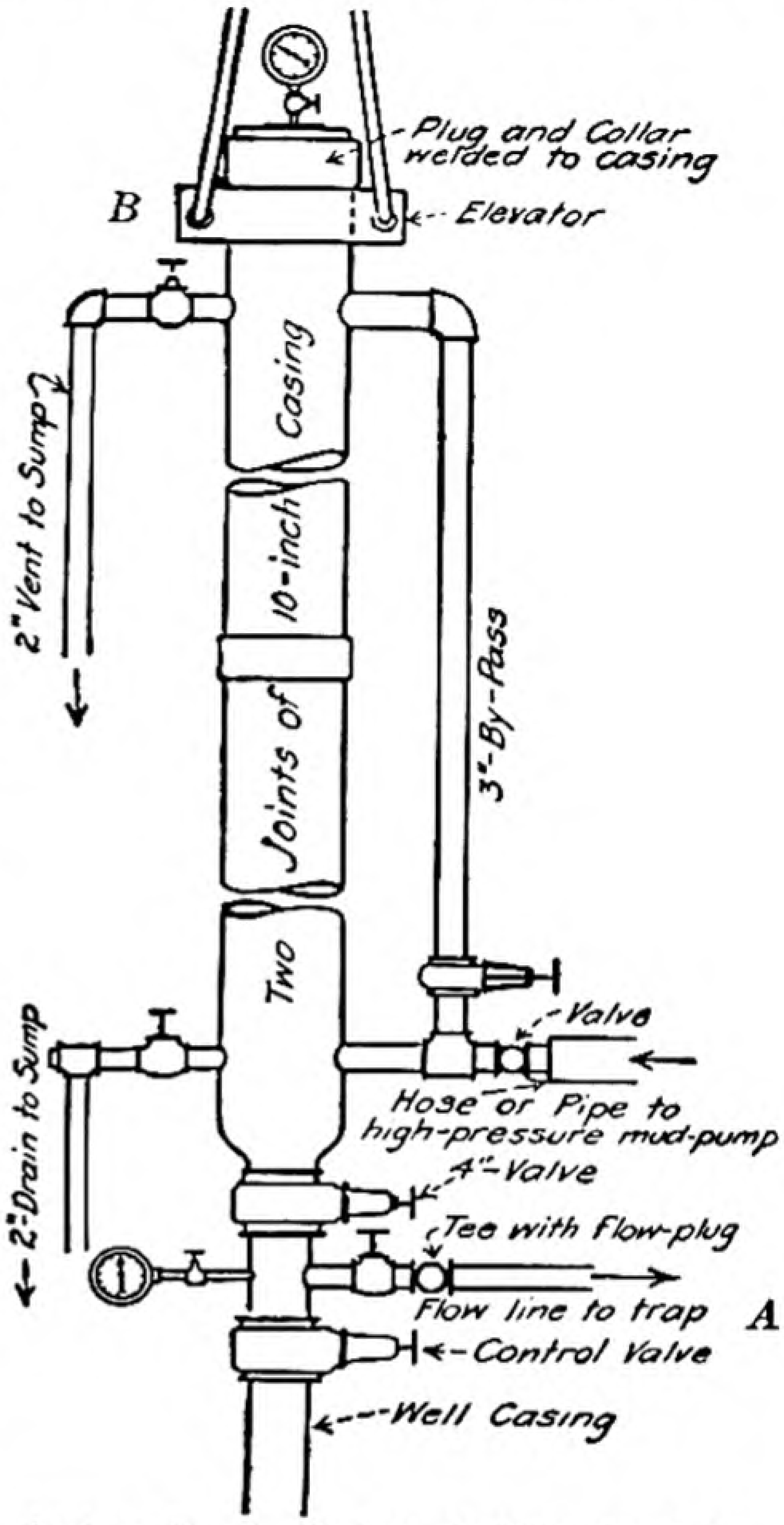
If gas enters and mixes with the circulating fluid, the density of the latter may be considerably reduced by gas occlusion, thus reducing the hydrostatic head on the well and the effectiveness of the mud in resisting the gas pressure. Fresh fluid should be circulated continually through the well, and the mud should be screened on reaching the surface to free it from occluded gas before again pumping it into the well. Blowouts sometimes occur during removal of the drill stem from the well. Displacement of fluid by the stem results in considerable subsidence of the fluid level when the stem is withdrawn, with consequent decrease in the hydrostatic head opposing a high-pressure sand in the bottom. More fluid should be introduced at such times, or the mud should be thickened.

Mudding under Pressure.—If a high-pressure sand is suddenly encountered with rotary tools in the well and there has been insufficient time to thicken the mud fluid to resist it properly, at the first sign of instability of forces within the well the blowout preventer is closed and drilling is discontinued. The mud in the slush pit is thickened by the addition of clay until a mixture as thick as the pump will handle is obtained. As this thicker mixture is pumped into the well through the drill stem, the pressure builds up until a sufficient pump pressure is added to the natural hydrostatic head to offset the pressure in the sand. Excess pressure beyond this point forces the well fluid into the sand, and, as the fluid is absorbed, the sand pores gradually become clogged with clay until the openings by which the gas enters the well are closed. By this time the heavier mud will also have considerably increased the normal hydrostatic head so that the pump pressure can gradually be reduced; the blowout preventer is then cautiously opened and circulation is resumed. Slow drilling with frequent rest intervals for mudding under pressure will usually enable the tools to penetrate the high-pressure sand without loss of control.

Use of the Lubricator.—If the drilling tools are out of the hole when a blowout occurs and it is possible to close the outlet either with the aid of a blowout preventer or a control casing head or both, a somewhat different procedure must be adopted. The problem now presented is that of placing more mud in the well so that greater hydrostatic resistance may be exerted by the well fluid. In order to accomplish this without releasing the pent-up forces within the well, a device called a "lubricator" is rigged above the casing head. This consists of two joints of casing about 10 in. in diameter, connected by a coupling, with a tee at the bottom, which, in turn, is connected by a nipple to the top outlet of the control casing head, or control valve *A* (see Fig. 260). Near its upper end, the 10-in. casing connects through a reducer to a 2-in. pipe which, by means of two elbows and a nipple, is led down at one side of the 10-in. casing to about the level of the derrick floor, and thence to the mud pit. A control valve *B* is placed in this 2-in. line at some convenient point outside of the derrick. A 3-in. line connects the side outlet at the lower end of the 10-in. pipe with a high-pressure slush pump. All pipe and fittings should be capable of withstanding heavy pressures.

With valve *A* closed and *B* open, a thick mud is prepared in the mud pit and pumped through the 10-in. casing until it overflows through the 2-in. line which returns the excess to the mud pit. The pump is then stopped, valve *B* is closed and *A* is opened. The mud in the lubricator, by reason of its excess of density over that

of the well fluid, sinks through the casing to the bottom of the well. Valve A is then closed, B is opened and the process is repeated until the well fluid has been greatly increased in density and a considerable depth of thick mud has settled to the bottom of the well. Pump pressure may then be applied by closing valve B, opening A and operating the pump, thus forcing the thickened fluid to flow into the high-pressure sand, depositing its clay in the sand pores about the walls of the well. After the formation ceases to absorb the well fluid under high pump pressure, the pump is stopped and valve B is cautiously opened. If the fluid is not ejected, it may be assumed that the high-pressure sand has been effectively sealed and the lubricator is removed and drilling continued.



(*After H. J. Steiny, California State Mining Bureau, Department of Oil and Gas.*)

FIG. 260.—"Lubricator" for use in mudding high-pressure wells.

If the cable tools are used, alternate drilling and mudding in this manner will make it possible to penetrate the high-pressure sand and continue to greater depths if desired; but care should be taken not to permit too low a fluid level on the sand, or the pressure may clear the sand pores of mud and cause a recurrence of the difficulty.

Use of the Circulating Head in Controlling High-pressure Wells with Mud-laden Fluid. The circulating head and mud-pumping equipment described in connection with the standard circulating system of drilling offers a convenient means of controlling high pressure in wells drilled with cable tools (see page 196). If the presence of a high-pressure sand is known or expected, the circulating head should be placed on the casing before penetrating it. In this device the space about the drilling cable within the head is packed off with a stuffing box. If high-pressure gas is encountered, heavy mud is pumped through the side outlets of the head, and pump pressure is maintained until the sand is sealed. If cable drilling is in progress and an unexpected flow of high-pressure gas is encountered, the pressure may be brought under control with the aid of a lubricator and a circulating head is placed on the casing to take care of further mudding before drilling is resumed.

Placing Mud-laden Fluid in a Well That Cannot Be Shut In.—It will occasionally happen that a well in process of drilling with cable tools cannot be shut in, either because the casing has not been landed and gas finds its way to the surface outside of the casing, or because it would be unsafe to subject the casing and fittings to the prevailing pressure. In such a case it would be impossible to use the lubricator in the manner described above and another method of introducing the fluid must be adopted.

Often, at some point above the high-pressure sand, there will be a conductor string landed, on which a tee casing head may be placed. A string of 2- or 3-in. tubing is lowered to bottom through the top opening of the tee, and the space around it is packed off so that it is secure against gas pressure. The lower end of the tubing is equipped with a back-pressure valve or a loosely placed wooden plug which can be forced out by pump pressure, while the side outlet of the tee is controlled by a gate valve. Mud is pumped down through the tubing to the bottom of the well, the

gate valve being partly closed to prevent it from being blown out by the gas pressure until there is sufficient mud within the well to offset the pressure. The outlet may then be closed and pump pressure applied to force fluid into the sand.

If the gas pressure is not too high, mud may be introduced by setting the casing on bottom after the high-pressure sand has been penetrated, filling the casing with mud; and then lifting it slightly so that the mud rapidly rises in the space about the casing, inundating the gas sand. By this procedure the well is usually filled to a point between two-thirds and three-fourths of its depth, and the height of fluid is in many cases sufficient to offset the gas pressure. Unless there is a large clearance between the walls of the well and the casing, there is danger of the casing becoming frozen when this method is used, and in some instances collapse of the casing has resulted.

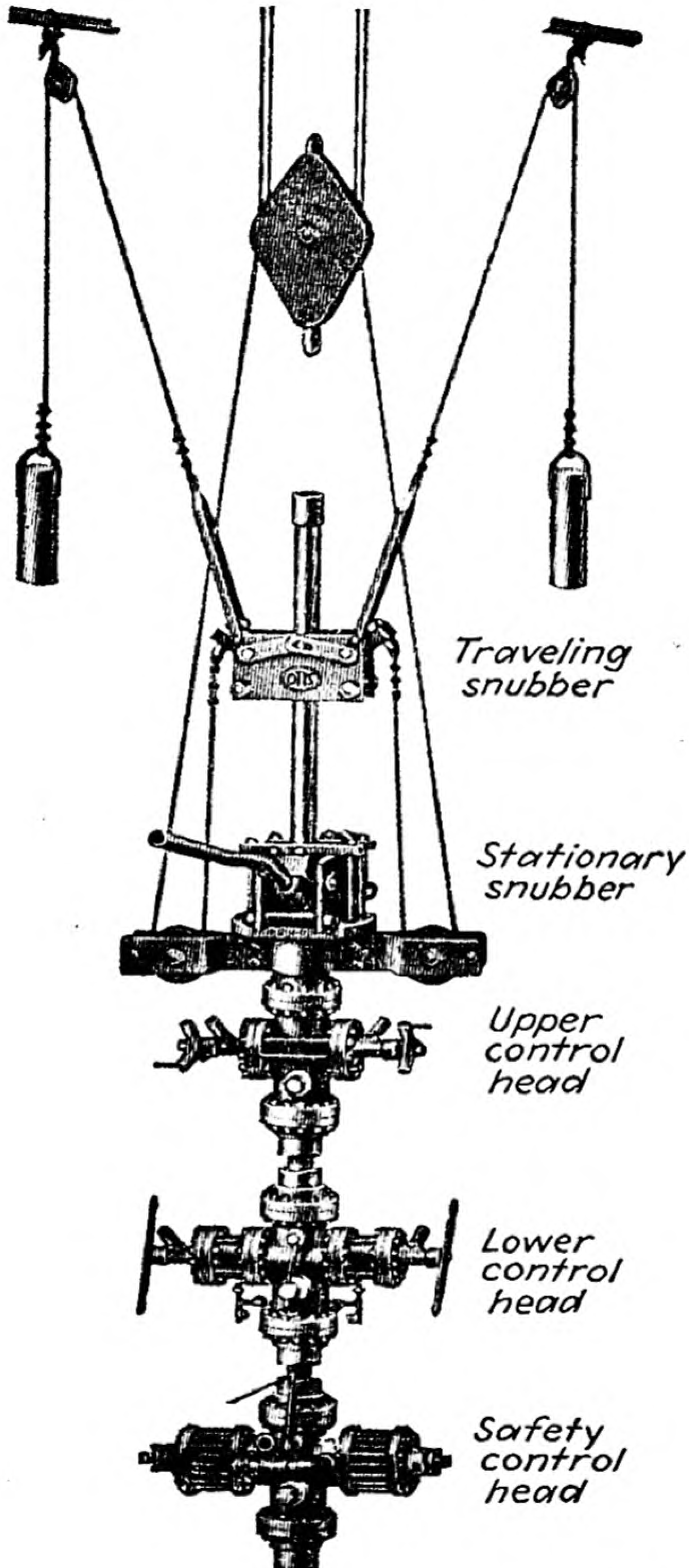
It may seem desirable or necessary at times to introduce mud-laden fluid at the surface into the space around the outside of the casing, or between two strings of casing. This should be avoided, however, if possible, since in flowing down the walls of the well the fluid often loosens much coarse material which settles about the collars and freezes the pipe.

"Snubbing" Tubing or Drill Pipe into or from High-pressure Wells

A problem sometimes presented is that of running in or withdrawing tubing or drill pipe from wells that cannot be opened to the atmosphere at the casing head without danger of a blowout of drilling fluid, or high-pressure oil or gas. Such a condition will perhaps occur when completing a well under reduced pressure control, or when the wells accidentally or prematurely come into production and develop high casing-head pressure with the drill pipe in the well. It becomes necessary then to rig special equipment in the derrick which will permit forcing the tubing into the well through fluidtight connections on the well head or which will control ejection of the tubing from the well. For this purpose, special "snubbing" equipment is available.

The Otis snubbing and control equipment, pictured in Fig. 261, is well designed for this purpose. This equipment makes use of two snubbers, one traveling, and the other stationary. The function of the traveling snubber is to force the pipe into the well against pressure, whereas the stationary snubber prevents it from being lifted out of the well by the fluid pressure. The stationary snubber is bolted directly to the casing. A cable passes from the control latches on either side of the traveling snubber, down under sheaves, one on either side of a clamp, and thence up over a traveling block. Upward movement of the traveling block thus results in downward movement of the traveling snubber forcing the tubing down with it. The stationary snubber permits free downward movement of the tubing, but prevents the tubing from being forced out of the well while the traveling snubber is being raised for a new hold. The two control heads shown below the stationary snubber are so constructed that they completely encircle the tubing with close-fitting hydraulic or composition packing. Rams in these heads are compressed about the tubing by manually controlled screw mechanisms, gripping the pipe as firmly as the well pressure may require. When necessary to pass a coupling, only one control head at a time is opened. Forcing pipe into the well in this way requires the use of rapid and safe

snubbing equipment until the tubing reaches a sufficient depth to offset, by its own weight, the lifting effect of the well pressure. Simpler types of equipment are also available for use under relatively low well-head pressures (less than 300 lb. per sq. in.).



(*Courtesy of Otis Pressure Control, Inc.*)
FIG. 261.—Otis snubbing and control equipment.

These provide gastight rubber seals, compressed against the pipe by well pressure, which are capable of expanding sufficiently to pass tubing collars or tool joints. Two such seals, one below the other, afford reasonable security against leakage. Other

snubbing devices are described in the companion volume of this work (see "Oil Field Exploitation," pages 141–144).

Capping a Flowing Well

If a blowout occurs and no control devices have been provided at the casing head, the well may get so far out of control that the flow of mud, oil and gas makes it difficult to attach a control head or valve on the casing. Since the well will continue to flow with great loss of oil and gas until checked in some way, it is necessary at once to undertake capping operations. This involves placing a valve of some sort on the outlet.

The valve to be employed is of the flanged-gate type and should be of massive construction to withstand the high closed-in pressure to which it is likely to be subjected (see Fig. 257). This "master valve" is suspended over the mouth of the well in the derrick and is gradually lowered on a previously placed flanged connection on the casing, while the stream of gas and oil passes through the open gate valve. When the flanges have been bolted together, the valve is slowly closed until the well is brought under control. Additional control valves, fittings and flow connections such as are described on page 598 may then be connected above the master valve before the well is again permitted to produce.

Anchoring Casing and Control Valves.—The upward pressure exerted by gas enclosed within the casing by closing the outlet is in some cases great enough to place considerable strain upon the connections at the casing head. In some instances pressures have been sufficient to lift the casing bodily out of the well. To offset this tendency, it is customary to anchor the control valves or casing head to the derrick sills with the aid of a heavy steel clamp and long bolts. In order to give additional security, some operators construct a heavy block of concrete about the casing below the derrick floor, embedding the anchor bolts in the concrete in such a way as to prevent the pipe from moving.

Protection of Workmen about High-pressure Wells

It is obvious that considerable risk is attached to the conduct of work about high-pressure wells, and every precaution should be taken against accident. Excessive pressure may result in the failure of control valves or fittings about the casing head, which are shattered with explosive violence. A sudden rush of high-pressure gas, accompanied by mud or oil, may wreck the derrick or force the drill stem or casings out of the well. The position of the derrick man in such an event is particularly dangerous. A safety device in the form of a wire-rope sling, which enables the derrick man to slide down one of the guy wires to safety, has been rather widely adopted. The stems controlling blowout preventers and control heads

should be so extended that they may be adjusted in case of necessity from a point outside of the derrick.

Capping operations are often conducted in the presence of large quantities of highly inflammable oil and gas, ready to explode or flash into flame on the slightest incitement. Although natural gas is not poisonous or asphyxiating unless hydrogen sulphide is present, the mere absence of oxygen in an atmosphere so laden with methane and oil vapor may make work about the well difficult and even dangerous. The use of self-contained oxygen breathing apparatus about oil and gas wells under such conditions offers a possible solution for this difficulty. Every precaution must be taken against fire.

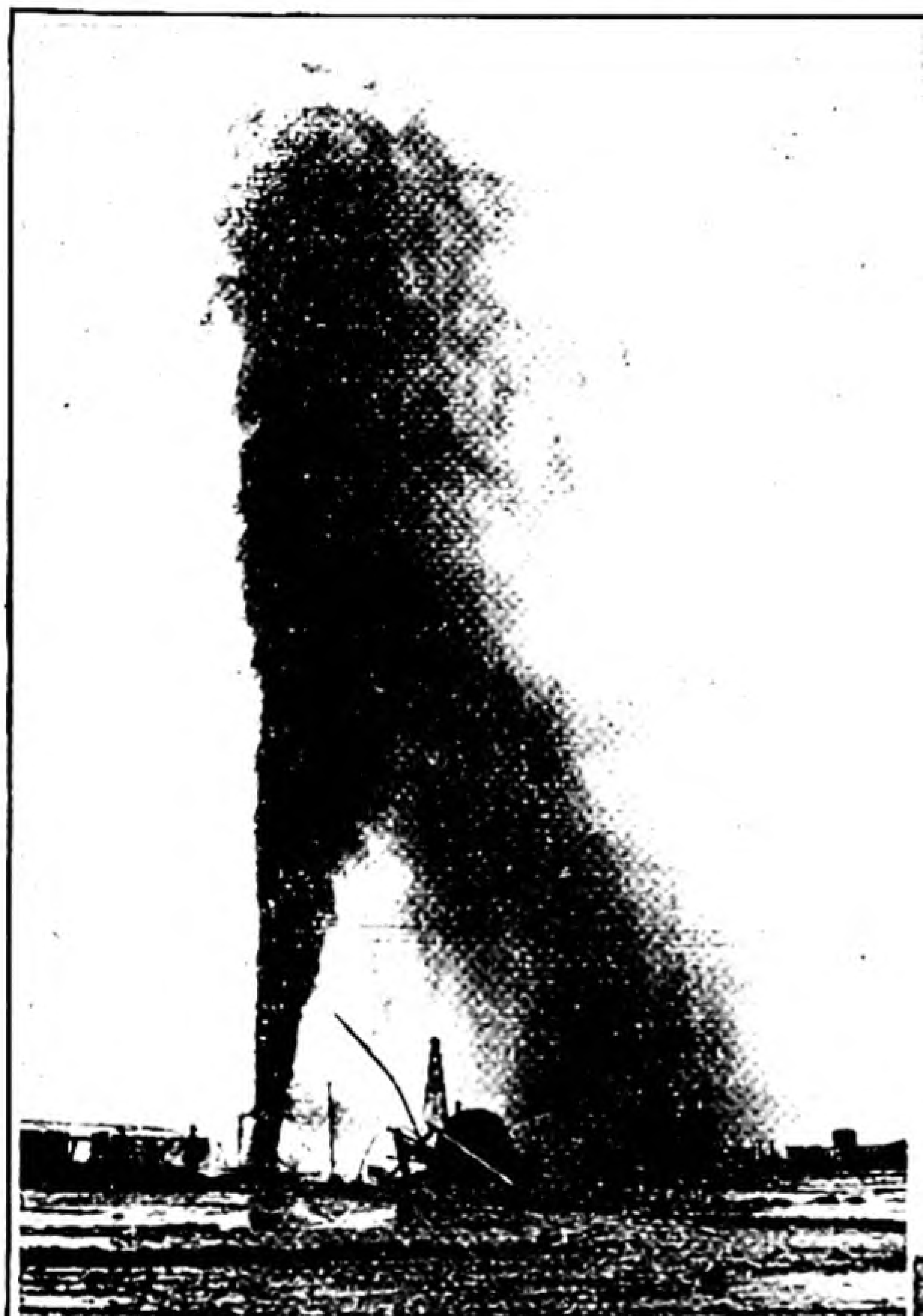


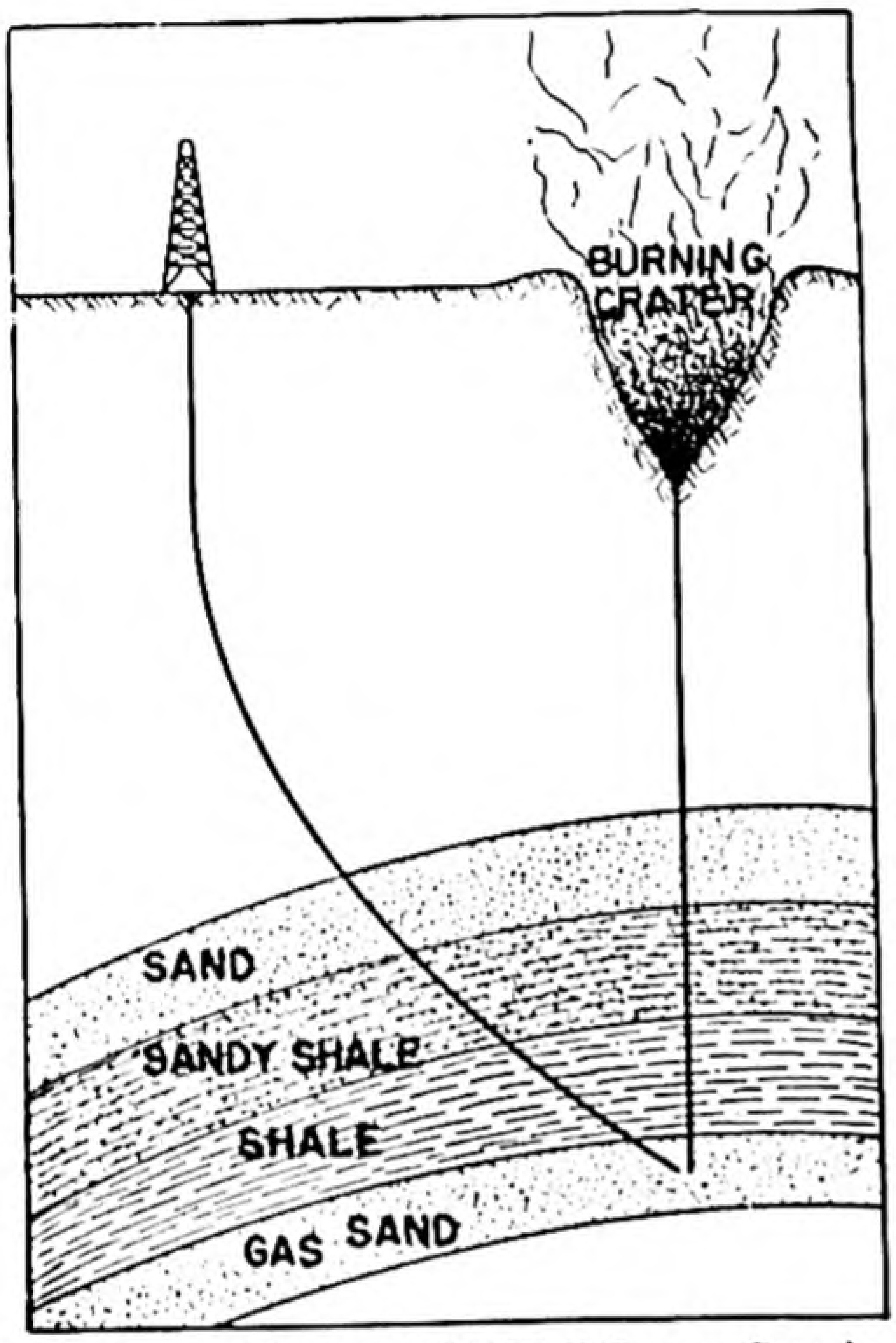
Fig. 262.—Lakeview No. 2 gusher, Sunset field, Calif.

Fig. 263.—A gusher fire, Elk Hills field, Calif.

Prevention and Control of Oil- and Gas-well Fires

The destruction wrought by the firing of a well producing large quantities of oil and gas under high pressure has been demonstrated in many fields. Aside from great losses of oil and gas from the burning of the well itself, the danger to other near-by wells and surrounding property usually requires prompt action in controlling and extinguishing it. The conditions attending such a conflagration present a problem in control of natural forces very difficult of solution. The column of flame may

extend for several hundred feet into the air above the casing head (see Fig. 263). If the well produces more oil than the flames can consume while in the air, the surrounding terrain may be deluged with burning oil. The derrick and wooden portions of the drilling plant are rapidly consumed, and the metal portions are converted into a mass of twisted iron and steel. This and the intense heat prevent close approach to the casing head. The casings projecting from the well mouth are often so damaged that they offer little opportunity for shutting in the flow even though means of approach and control of the fire are possible.



(Courtesy of Eastman Oil Well Survey Corp.)

FIG. 264.—Method of extinguishing cratered fire well through secondary directionally drilled well.

Gas-well Fires.—Gas-well fires are easier to extinguish than oil-well fires, for the reason that the gas is completely consumed and the flame is confined to a well-defined column of no great thickness. The force of the flowing gas and scarcity of oxygen, except about the periphery of the ascending stream, usually prevent the gas from burning until it is well above the outlet. As the column ascends, however, air is drawn in and mixed with the gas so that it burns freely.

If the gas flow can be momentarily interrupted, it will usually be extinguished. It is customary to resort to the use of steam to accomplish this. A large volume of steam suddenly and forcibly applied immediately above the casing head, against the stream of gas, cuts off the supply of oxygen necessary to support combustion and smothers the flame. Incidentally, the steam serves to cool the ascending vapors and metal objects about the well and casing head.

In combating gas-well fires with steam, a battery of portable boilers—frequently 20 or more—of the type used in furnishing power for drilling operations is assembled about the well at a safe distance. Steam pipes equipped with goosenecks terminating in flattened nozzles are connected with the boilers, pushed forward toward the fire and adjusted so that the nozzles will direct their jets of steam directly against the outlet of the casing head. The boilers are fired and a supply of high-pressure steam is suddenly discharged into the fire from all sides and, if possible, maintained for several minutes after the fire is extinguished. Sprays of water similarly directed are sometimes successful, the water being converted into a blanket of steam on contact with the flame. A 40,000,000-cu. ft. gas-well fire near Monroe, La., was successfully extinguished by this method.

Another method commonly employed in extinguishing gas-well fires involves the lowering of a large-diameter pipe in a vertical position over the well, in such a way as to enclose the burning column of gas. The pipe serves to prevent admixture of air with the gas until it has passed through the pipe, the flame being confined to the gas above the upper end. The pipe is simply allowed to topple over, throwing the flame to one side of, and to a safe distance from, the well.

A method of successfully combating gas-well fires involving the use of explosives has been applied in several instances. A fire well in the Elk Hills field had defied efforts to extinguish it with steam and carbon tetrachloride, when the use of explosives was suggested. Wooden towers erected on two opposite sides of the well provided a means of stretching a cable a few feet from one side of the column of flame, which extended 200 ft. into the air above the casing head. A small carriage was rigged, suspended on two flanged pulleys traveling on the cable, and a second pull rope provided a means of moving the carriage along the cable. A charge of 150 lb. of blasting gelatin was suspended from the carriage and the latter moved along the cable until it reached a position near the column of flame. The explosive was then detonated electrically. Observers state that the flame was literally blown out by the force of the explosion, the upper part of the column being blown upward, the lower part downward and the central portion horizontally away from the position of the explosive. A number of boilers were fired and the steam, with about 100 bbl. of carbon tetrachloride, was brought to bear upon the base of the fire at the time of the explosion. This particular well ranks as one of the world's largest gas wells, the flow being in excess of 100,000,000 cu. ft. at the time of the fire. It was ignited by friction of the gas, carrying large quantities of shale and sand, upon the 6-in. flow line through which the gas was ejected from the well. Explosives have since been successfully used in a somewhat similar manner in extinguishing several oil and gas fires in the fields of southern California and in Texas and Oklahoma.

Oil-well Fires.—In the case of an oil-well fire, the flame is not usually confined to a well-defined column, as in the case of gas. Burning oil falls all about the well so that the source of the fire is more difficult of approach. The casing head and metal parts of the rig become heated so that they often reignite the oil after it has been extinguished, unless it can be kept under control for a sufficient time for surrounding objects to cool.

Many spectacular oil-well fires have been experienced in the American fields, and published accounts of them provide interesting reading and describe many ingenious methods used in extinguishing and controlling them. The methods employed necessarily vary with the size of the fire and the surrounding conditions. Steam is customarily employed, as described above, but in the case of certain large fires has been unsuccessful. In one instance, a 1,000-bbl. well became ignited, and, owing to lateral deflection of the stream of oil as a result of collapse of the casing head, a crater 50 ft. in diameter and 40 ft. deep was formed about the well. A large number of boilers were set up near the well and steam and water applied in the usual way. Though the fire was repeatedly extinguished, the heated walls of the crater reignited it as soon as the blanket of steam cleared. This fire was eventually extinguished by flooding the crater with

mud, mixed in a large reservoir specially constructed near by. Steam formed from the mud extinguished the fire, and the mud plastered and cooled the walls of the crater.

In another case of a fire well producing 48,000 bbl. of oil daily, it was found impossible to extinguish the flame with 36 boilers.[5] A circular levee 3 ft. high and 200 ft. in diameter was constructed about the well to confine the burning oil, and a 328-ft. tunnel was driven to intersect the well casing at a depth of 18 ft. below the surface. The well contained three strings of casing, 10, 8 and 6 in. A split clamp was placed around the 10-in. casing and to this was attached a 6-in. pipe extending beyond the portal of the tunnel. An especially constructed bit made from a casehardened nipple was screwed on the end of a line of 4-in. pipe extending through the 6-in. line and equipped at its outer end with a cap and sprocket wheel to which was attached a rotary chain drive. A screw jack set against a post served to force the bit against the pipe as the 4-in. line revolved. Rotating the 4-in. pipe and bit caused the latter to cut a hole through all three casings, care being taken to stop the bit in the center of the 6-in. casing. A hole previously cut in the bit was turned so that asbestos shavings pumped under pressure through the 4-in. pipe were forced down into the stream of ascending oil and accumulated about the bit, closing the small spaces about it and cutting off the supply of oil to the surface. The tunneling method was also successfully used in extinguishing an oil-well fire in the Santa Fe Springs field of California that resisted all efforts to extinguish it by other methods for a period of 7 weeks.

Directional drilling affords an interesting means of controlling fire wells. In several instances, a well has been drilled from a location at a safe distance from the burning well and deflected with the aid of surveying instruments and deflection tools, so that it intersected the producing formations in the immediate vicinity of the area from which the fire well derived its supply of oil and gas. Water or drilling fluid was then forced through the deflected well into the reservoir strata, cutting off the supply of combustible material to the burning well and thus extinguishing the fire (see Fig. 264).

The work of combating oil fires is hazardous and difficult. The temperatures to which workmen are exposed are extreme. Such work as adjusting steam lines and nozzles and making preliminary arrangements requires that the workmen approach as nearly as possible to the well. At such times they may be partly protected by sheet-metal or asbestos shields pushed ahead of them as they advance. It may be necessary to spray the workmen continually with water and dress them in asbestos clothing.

Precautionary Measures.—The destruction wrought by oil- or gas-well fires and the difficulty experienced in their control justify the use of every possible means of preventing and combating them in the incipient stages. Forges for dressing tools should not be placed in the derrick. Boilers should be placed at a reasonable distance away from the well so that a sudden flow of gas or oil may not come into contact with the boiler fires. Place wire spark screens over the boiler stacks and keep all dry grass and other vegetation cleared from about the rig. Electric lights should be used in preference to any form of lamp or torch. A small steam-turbine-driven dynamo will generate enough electricity for lighting purposes, if current is not otherwise available. If the well is

flowing gas or oil, it is safer to floodlight the rig from lights placed on poles outside of the derrick. Wiring in or on the derrick is a menace. Avoid frictional heat in bearings of moving parts of the rig by frequent lubrication. Static electricity generated by the band-wheel belt, by the brakes or other moving parts has often caused fires. All parts should be properly grounded, and belts should be provided with copper brushes attached to a grounded pipe. Two pieces of steel struck forcibly together may form a spark which will ignite gas; or rocks blown from the well by explosives or by gas flow, striking the metal crown blocks or rig irons, may start a fire. Smoking should be prohibited in and about the rig. If matches are necessary, only the safety variety should be permitted. Gas often flows for considerable distances in ravines and depressions screened from wind currents, and instances are on record where gas accidentally ignited at some distance from a well has "struck back" along the communicating channel of gas, firing the well.

Although precautionary measures are commendable, preventive measures involving control of the gas and oil are of greater importance. Mudding to restrict escape of gas while drilling is in progress and adequate valve control to cut off the supply of oil and gas in case of a fire are the best preventives.

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CHAPTER XV

WELL RECORDS: LOGGING METHODS AND RECORDS

Many millions of dollars are expended annually in the drilling of new oil and gas wells. The results secured from this great expenditure are measured not alone in oil and gas produced but also in information relative to subsurface conditions. So valuable is this information to the oil producer in the subsequent development and exploitation of his property that he is justified in spending considerable sums in assembling and recording it. Increasing emphasis is given to this work by the more progressive oil companies. Up-to-date executives realize that the more technical and exacting methods of the future will require more complete and accurate records than have those of the past.

A handicap that the engineer of today must contend with in seeking to apply new methods in the older fields is the lack of suitable records of the early drilling. One often finds that very inadequate records are available: no logs of the wells, no production records; perhaps little is known of the thickness and character of the reservoir rock, the depth of water-bearing horizons and other matters of great practical importance. Such information is often essential in the conduct of future development work, in diagnosing production troubles, in planning well repairs, in making appraisals, in the application of improved methods of recovery and in other similar engineering problems.

Today, the modern core drill brings to the surface representative samples of the formation penetrated, upon which lithologic tests may be made and the characteristics of the material determined. Instruments are available through the use of which the exact course of a well—that is, its direction and amount of deviation from the vertical—may be estimated. Methods for correlating formations from well to well have been developed, so that the inclination and strike of strata may be determined. Improved equipment and technic have provided the means of securing more detailed and accurate information of subsurface conditions.

With this superior knowledge has come the necessity for recording it in a manner that will serve not only our own immediate needs but also the requirements of the petroleum engineer of the next generation, who will look to us for the record of what we do and learn in the active fields of today. Most of the larger oil companies recognize this obligation and are employing engineers, geologists, chemists, physicists and paleontol-

ogists to gather data in the field, make the necessary tests and inspections in the laboratory and assemble the information in suitable records in the office.

IDENTIFYING FORMATIONS AND GATHERING LOG DATA WITH THE CABLE-TOOL EQUIPMENT

The cable-tool driller is able to identify the kind of rock in which the drill is operating by the rate of progress, by the jar on the drilling cable and by the wear on the drilling tools. Cuttings brought

TABLE XLI.—MECHANICAL REACTIONS ON CABLE-TOOL DRILLING EQUIPMENT AND CHARACTER OF CUTTINGS OBTAINED FROM DIFFERENT TYPES OF SEDIMENTARY ROCKS*

Field and formation	Mechanical reactions	Cuttings	Effect on bit
Southern Oklahoma:			
Shale	Tools run smoothly and drill easily and fast in dry hole.	Bailer material mostly mud; fragments in mud and occasionally on bit.	Does not wear bit.
Gumbo	Drills roughly; tools jerk walking beam and do not drop freely.	Bailer material mud; tools come out loaded with gumbo.	Does not wear bit.
Soft sand	Drills fast and easily; tools plunge.	Sand in bailer; none on bit.	No wear on bit, but markings vertical.
Sandstone	Drills smoothly with occasional "kick back."	Grains of sand and chunks of sandstone in bailer.	Wears bit out of gauge.
Limestone	Hard and slow drilling; big "kick back."	Chips and irregular pieces, rock mostly pulverized.	Wears bit, but does not cause to lose gauge like sandstone.
Gypsum	Drills smoothly and more easily than crystalline limestone.	Mostly pulverized; occasional flakes.	Does not wear bit excessively.
Ranger field, Texas:			
White limestone	Drills hard but free, with tight line.	White and pulverized.	Cuts bit badly—3 bits per tour.
Shale	Drills fast and easily in dry hole.	Chunks and fragments in bailer and small pieces stuck to bit.	Does not cut bit.
Black limestone	Drills hard, with tight line through oil saver.	Cuttings fine grained.	Cuts bit a little.
Wyoming fields:			
Hard shell	Drills clean with increased motion.	Occasional fragments in bailer.	Does not wear bit rapidly; cuts it vertically like sand.
Limestone	Drills clean with increased motion.	Cuttings fine grained and heavy.	Does not wear bit badly.
Shale, slate, etc.	Drills fast in dry hole, except when cavy. Slow motion.	Fragments of material in bailer.	Very little wear, but "dubs bit under."
Sandstone	Drills clean and free.	Cuttings show as sand grains and fragments of cemented grains.	Cuts bit badly, vertically.

* After R. E. Collom, *U. S. Bur. Mines Bull.* 201.

up by the bailer, when thoroughly washed to free them of mud, provide a means of identifying accurately the nature and mineral content of the stratum from which they come. Usually, too, a little of the material in the bottom clings to the drilling bit as it is withdrawn. Table XLI indicates the mechanical reactions and character of the cuttings obtained from different types of sedimentary rocks. The material brought up by the bailer is mostly mud, but by carefully stirring and washing a little of it in a bucket the coarser material may be segregated and examined.

Depth to bottom is determined at any time, by actual tape measurement, by measurement of the drilling cable or sand line or by recording the length of casing in the well, if the casing extends to bottom. For shallow wells a heavily weighted steel-wire tape coiled on a reel mounted at one side of the well may be lowered to bottom and the depth measured directly. In deep wells the magnetic drag of the tape on the casing is frequently so great that it is impossible to tell when the weight reaches bottom or to feel the "pickup" as the weight is lifted off bottom. Measurement on the drilling cable or sand line is probably more accurate if carefully done. For this purpose, the distance from the derrick floor over the crown and down to the upper flange of the sand reel, or to a point on the bull-wheel shaft 5 ft. above the derrick floor, is carefully determined by tape measurement, and one or the other of these units is applied on the sand line or drilling cable respectively, as described on page 527. Measurements are made while drawing the bailer or tools out of the hole, care being taken to record bottom on the pickup, that is, just as the sand line or cable receives the full weight of the bailer or tools on leaving bottom. If depths are determined by the casing record, an accurate measurement of all casing in the hole must be kept, lengths being measured from top to top of collars after the joints are securely screwed together.

The driller usually maintains a target or reference mark on the sand line or drilling cable, indicating the approximate depth to bottom, depths in excess of the reference mark being measured with the aid of a steel tape or a 5-ft. "stick," which is a part of the equipment of every cable drilling rig. Examination of well logs will show that many drillers do not attempt measurements within the 5-ft. length of the stick. Measurements involving lengths in excess of 100 or 200 ft. should not be attempted with the stick because of the inaccuracies involved. Measurement with the steel tape is always preferable. Usually the driller knows the depth to bottom at the beginning of each "screw," and when a change in formation is noted by the action of the drilling cable he has only to measure the length of temper screw paid out to record the depth at which the new formation was encountered.

TABLE XLII.—MECHANICAL REACTIONS AND PHYSICAL APPEARANCE OF THE CIRCULATING FLUID FOR VARIOUS SEDIMENTARY ROCKS IN THE PROCESS OF ROTARY DRILLING*

Field and formation	Action of pump and tools	Cuttings	Effect on bit
Midway Field, California:			
Hard sand...	Pump runs with low pressure, sand takes some fluid; tools jump.	Sand shows in ditch with thin mud.	Bit badly worn with only 1½ hr. drilling in hard sand.
Loose sand...	Pump runs with low pressure; frequently takes mud; necessary to thicken fluid; when bit is stopped and set on bottom, sand can be sluiced out with mud stream, causing tools to plunge.	Sand shows in ditch with thin mud.	Does not cut bit appreciably.
Sandy shale..	Pump runs with low pressure; digs like sand, but with bit set on bottom cannot sluice out any hole below it.	Fragments in ditch with thin mud; streaked samples on tools.	Cuts bits considerably.
Soft shale....	Pump runs with medium pressure.	Small fragments in ditch; soft chunks on bit, with streaks upon breaking.	Cuts bit very little.
Hard shale...	Pump runs with more pressure than in sand; tools jump.	Shows in ditch in small flakes and chunks; very little sticks to bit.	Cuts bit badly.
Clay	High pressure on pump; run thin fluid; pump sometimes stalled; machinery runs smoothly with tension on table and chains; necessary to spud tools in order to clean the bit.	Change of color is the only showing of clay formation in the ditch; plenty of clay sticks to the bit.	Does not cut bit.
Shell........	Pump runs freely; tools, chains and tables jump.	Small fragments show in thin mud in ditch.	Cuts bit badly.
Sea shells....	Pumps run freely, unless in clay.	Fragments and some perfect specimens show in ditch.	Does not cut bit.
Northern Louisiana fields			
Hard rock...	Pump runs slowly with low pressure.	Cuttings show in ditch in thin mud.	Wears bit badly and to all shapes.
Hard shell. Hard limestone.... Sand (hard and soft).	Run without much steam pressure; cuttings easy to handle.	Cuttings show in thin mud in ditch.	Wears bit badly and to all shapes.
Shale........	Run with nearly full head of steam; pumps handle cuttings without spudding but have to work hard.	Fragments show in ditch.	Does not wear bit appreciably.
Gumbo......	Run pump with full head of steam; even then continual spudding needed to mix cuttings enough to allow free returns.	Will ball up and shut down pump; no show except color in ditch.	Does not wear bit appreciably.
Chalk.......	Run pumps with full head of steam; does not ball up; sometimes have to spud.	Small fragments of hard chalk in thin mud.	Does not wear bit badly; hard streaks wear bit.
Gypsum.....	Does not take much steam pressure; pump can be run slowly; gypsum balls up on point of bit and retards progress, but has no effect on pump.	Shows in flakes or small particles in thin mud; balls up on bit.	Does not wear bit appreciably.
Salt.........	Drills slowly; returns not hard to handle; no effect on pump.	Small particles occasionally	Does not wear bit appreciably.
Southern Oklahoma:			
Shale, various colors.	Tools run smoothly, medium pump pressure; drills fast.	Fragments show in thin mud.	Does not wear bit appreciably.
Sandy shale..	Tools run smoothly, chain "settles down;" drills fast.	Fragments show in mud like shale.	Wears bit more than shales.
Gumbo......	Tools run in jerks; high pump pressure; hard to drill; driller has to reverse engine and spud tools to clean bit.	No show in ditch other than color; sticks to tools.	Does not cut bit.
Clay........	Tools run smoothly; easy drilling; high pump pressure.	Balls up on bit; no sample in ditch other than color.	Does not wear bit appreciably.
Limestones....	Tools jump and jerk when cutting; low steam pressure; hard to drill.	Fragments in ditch occasionally.	Wears bit and reduces its gage.

* After R. E. Collom, *U. S. Bur. Mines Bull.* 201.

IDENTIFYING FORMATIONS AND GATHERING LOG DATA WITH THE ROTARY EQUIPMENT

The rotary driller recognizes changes in formation by the action of the drill stem, the rotary table and the circulating pump. On withdrawing the drill stem from the hole, evidence concerning the nature of the material penetrated is also to be gained from the condition of the drilling bit. An examination of the drill cuttings brought to the surface by the circulating fluid and deposited in the mud ditch will indicate more definitely the lithological characteristics of the material in the bottom. Table XLII gives the mechanical reactions and physical appearance of the circulating fluid for each type of rock ordinarily encountered in sedimentary formations.*

Progress in depth is measured by the movement of the drill stem through the rotary table. The length of rotary drill pipe below the rotary table is definitely known at all times by steel-tape measurement, and the grief stem is usually marked at 12-in. intervals as a further aid for the driller in determining the depth at which each change in character of the formation is encountered.

In order to correlate the samples obtained from the circulating fluid with the mechanical reactions of the drill, it is necessary to determine approximately the time necessary for the circulating fluid to transport material from the bottom of the hole to the surface. This is a function of the speed and delivery capacity of the mud pump, the depth and diameter of the hole and the diameter of the drill stem. The delivery time may be computed with fair accuracy if these variables are known and can be readily checked by placing a quart or two of red paint or some distinctively colored dye in the pump suction and noting the time necessary for it to travel through the drill stem and back to the surface. The time necessary to reach bottom—which must of course be deducted from the round-trip time to determine the delivery time from the bottom to the surface—can be definitely determined if the delivery capacity of the pump and the length and internal diameter of the drill stem are known. Actually delivery times vary from a few minutes to as much as 2 or 3 hr. and average about 6 min. per 1,000 ft. of depth.

The mud ditch through which the well fluid flows from the well to the sump in which the surplus is stored is usually equipped near its upper end with riffles or depressions which serve to settle out and impound the coarser material. Samples useful in identifying formations may

* COLLOM, R. E., Prospecting and Testing for Oil and Gas, *U. S. Bur. Mines Bull.* 201, p. 101, 1922.

readily be secured by shoveling some of this coarse material from the ditch and washing thoroughly with clear water to remove the mud. If an uncontaminated sample from the stratum in which the bit is working is desired, drilling is stopped, but circulation is continued until no more cuttings are brought to the surface. The mud ditch is then shoveled out and drilling is resumed. At the expiration of the calculated time necessary for cuttings to reach the surface they are looked for in the mud ditch. Some drillers use a large-size thread protector (from the open end of a joint of casing) in the trench as a means of impounding a sample. If a vibrating screen is used, representative formation samples may be gathered from the material retained on the surface of the screen. Color plays an important part in the identification of materials in the mud ditch. Clays and shales will usually be so finely pulverized by the drill that the color imparted to the circulating fluid by them is the only means of identifying one stratum from another.

In some kinds of material, particularly clays and shales, drilling for a few minutes without circulation of fluid will ball up a mass of pulverized cuttings on the bit, which is brought to the surface when the drill stem is drawn out.

Because of the rapid progress made in soft formations and the difficulty of recognizing slight changes in the nature of strata penetrated, the rotary method does not yield so reliable and complete a log as the churn drilling method. A body of rapidly alternating layers of shale, sand and clay, for example, will usually be logged as a single stratum of sandy shale, that is, the rotary drill logs show fewer formation changes and seemingly thicker beds. Mechanical difficulties in operation of the drill will often be interpreted as due to hard rock. The "boulders" commonly found in rotary logs, for example, are in most cases inferred from the action of the drill on hard strata and on bodies of shale.

The data incorporated in the well logs must be collected for the most part by the drillers, though the average driller is poorly equipped for the work of identifying the mineralogical and lithological characteristics of the formations penetrated. The driller usually has at his command a limited vocabulary of colloquial rock names, often local names, which are based on the hardness, toughness and color of the material rather than upon any petrographic classification. However, he is usually able to distinguish such common materials as sand, sandstone, limestone, clay, shale and conglomerate, and, supplemented by descriptions of color and texture, for most purposes this identification is sufficient if carefully and accurately done. The colors recorded are ordinarily those exhibited by the wet material as it comes from the well. For more accurate

SPECIMEN WELL-LOG RECORD

(Front Side.)

FIELD *Coalinga*

COMPANY *California Oilfields, Limited (Shell Co. of California)*

LOG OF WELL NO. **78**

DESCRIPTION OF PROPERTY *(Quarter Section) S. W. ¼ of Sec.* ***27, 19/15***

LOCATION OF WELL *740′ N. and 2905′ W. of S. E. corner*

ELEVATION ABOVE SEA LEVEL *1,178 ft.*

COMMENCED DRILLING *Oct. 29, 1913.* FINISHED DRILLING—*See History*

Depth from—	To—	Feet.	Formation.
0	10	10	Brown adobe.
10	25	15	Brown sand.
25	55	50	Yellow clay.
55	65	10	Coarse gray sand.
65	98	33	Black gravel.
98	125	27	Brown sand.
125	185	60	Blue sandy shale.
185	210	25	Light blue shale.
210	245	35	Coarse gray sand.
245	315	70	Light blue shale.
315	317	2	Brown shale.
317	330	13	Blue shale.
330	390	60	Sandy blue shale.
390	404	14	Fine gray sand.
404	440	36	Light green shale.
440	450	10	Gray sand.
450	478	28	Coarse gray sand and **gravel.**
478	497	19	Gray sandy shale.
497	510	13	Coarse gray sand.
510	535	25	Sandy blue shale.
535	580	45	Blue shale.
580	640	60	Sandy blue shale.
640	690	50	Gray sand, **shows tar oil.**
690	705	15	Blue shale.
705	715	10	Sandy blue shale.
715	723	8	Gray sand, **shows tar oil.**
723	733	10	Fine hard gray sand.
733	740	7	Hard sand shell.
740	753	13	Gray sand, **shows tar oil.**
753	757	4	Blue sand shell.
757	785	28	Soft gray sand.
785	796	11	Blue shale.
796	797	1	Hard sand shell.
797	805	9	Soft sand and gravel, **Water.** (Water stands at 600′.)
805	806	1	Hard sand shell.
806	870	64	Sticky blue shale.
870	905	35	Fine gray sand.
905	920	15	White sand and sea shells. **(Put in 2 loads red mud at about 930′.)**
920	965	45	Soft gray sand.
965	985	20	Sandy blue shale.
985	1,005	20	Sandy shale, black.
1,005	1,055	50	Fine soft gray sand.
1,055	1,092	37	Hard coarse gray sand.
1,092	1,104	12	Sticky black shale.
1,104	1,129	25	Sticky light blue shale.
1,129	1,140	11	Light gray slate.
1,140	1,214	74	Tough green shale. **(12½″ casing cemented at 1216′.)**
1,214	1,232	18	Tough, sticky green shale.
1,232	1,280	48	Light green shale.
1,280	1,295	15	Light blue shale.
1,295	1,305	10	Light gray shell.
1,305	1,330	25	Sticky blue shale.
1,330	1,348	18	**HARD GRAY OIL SAND, fair**
1,348	1,363	15	**FINE GRAY OIL SAND, good.**
1,363	1,380	17	Hard gray sand, no oil.
1,380	1,393	13	**SOFT GRAY OIL SAND.**
1,393	1,410	17	Hard gray sand, no oil.
1,410	1,421	11	Black sandy shale.
1,421	1,423	2	Hard sand shell.
1,423	1,440	17	Fine black sand.
1,440	1,445	5	Hard sand shell.
1,445	1,470	25	Fine dark gray sand.
1,470	1,493	23	Sandy blue shale. **(10″ casing cemented at 1626′.)**
1,493	1,495	2	Hard sand shell.
1,495	1,500	5	Very sandy shale, **shows oil and gas.**
1,500	1 510	10	Soft fine gray sand, **shows oil.**
1,510	1,525	15	Light blue shale.
1,525	1,587	62	Gray sand, **shows oil and gas.**
1,587	1,598	11	Black sandy shale.
1,598	1,608	10	Hard fine gray sand, no oil.
1 608	1,620	12	Fine black sand, shows **Sulphur Water.**
1,620	1,629	9	Tough black shale.

Original, 8½ by 21½ in. in size.

SPECIMEN WELL-LOG RECORD (*Continued*)

(Reverse side.)

(LOG CONTINUED.)

HISTORY OF ORIGINAL DRILLING.

Casing froze at 1353'. Bailed to free the 10" casing and bailed dry. No record concerning water (12/15/13). Put in red mud, drilled ahead, finding 40'. Cavings in hole (12/16–18/13).

10" casing cemented at 1497' with 56 sacks cement dumped in (12/24/13). Cement 10' in casing, but bailed out 5'. Cement set to Mar. 16, 1914. Bailed hole dry, stood 6 hours and made no water. Drilled pocket to 1517', bailed hole dry, stood overnight and made 2 pails of water and a little oil. Then started to put in 8¼" casing. Drilled hole to 1620'; well showed evidence of sulphur water.

8¼" casing. Had in 1581' of 8¼" casing and then pulled two joints and bailed hole dry, stood 5 hours, and made 168' of water and no oil. Bailed hole dry and sand filled hole up to 1550'. Bailed at 1-hour intervals and well made 5 bailers (6¾" by 40') each run of black water, "smelling strongly of sulphuretted hydrogen. There is also a little oil" (3/24/14).

Bailed, hole made 5 bailers per hour of water with a little tar oil. Made 10 bailers after standing 2 hours (3/25/14). Bailed hole, made 5 bailers per hour of black sulphur water with a little tar oil (3/26/14). Bailed; no change in quantity of water or oil (3/27–30/14).

Pulled so as to loosen 10" casing and cement it lower in order to shut off sulphur water (3/31/14).

10" casing. Got 10" vibration at 1425'. Filled hole from 1501' to 1497' with brick and cement. Put in 5 sacks cement and drove two wooden plugs into cement, top of plugs at 1490'. Dumped in 10 sacks cement and drove two wooden plugs, filling hole to 1462'.

Ripped 1425' to 1455' and filled hole to 1385' with 19 sacks cement, broken concrete, M. & F. plugs. Dumped in wheelbarrow load of gravel and ripped 10" casing at 1345' to 1370'. Put in 4 sacks cement, filling hole to 1365'.

Pulled 1335' (4/11/14), left 162'. 1335' to 1497' to be cased off. Drilled to 1395' and found tools following old hole. Filled to 1370' with bricks and 8" by 8" timbers, then drilled past casing to 1629'. Reamed to 1626'.

10" casing cemented at 1626' (4/29/14) with 73 sacks cement dumped in. Ran in and found cement 10' up in casing. Shut down for cement to set.

Idle until August 23, 1916.

HISTORY OF PLUGGING AND PERFORATING.

10" casing. Drilled pocket to 1630' (8/25/16). Bailed dry at 3-hour intervals.) Made 3½ barrels of water per hour. Tested by bailing from Sept. 30, 1916, to Oct. 1, 1916. Made 2½ barrels of water per hour.

Plugged to 1587' feet with 50 sacks cement, Sept. 2, 1916. Perforated by machine as follows: 1330–1410; 1423–1470; 1529–1580.

Bailed. Made 29 barrels of oil in 24 hours. Small show of water, Sept. 15, 1916. Tubed at 1480' with 3" tubing Sept. 30, 1916.

Production. About 40 b/d and no water. Gravity 25.3.

CASING RECORD.

15½ in. landed at *834* ft., cut at (*All Pulled*) ft., weighing *70* lbs. brand *DBX* (*11/17/13*)
12½ in. cemented at *1214* ft., cut at ft., weighing *40* lbs. brand *DBX* (*12/3/13*)
10 in. cemented at *1626* ft., cut at ft., weighing *48* lbs. brand *DBX* (*4/29/14*)

OIL AND GAS SANDS.

From *640* ft. to *690* ft.	From *1380* ft. to *1393* ft.
From *715* ft. to *723* ft.	From *1500* ft. to *1510* ft.
From *740* ft. to *753* ft.	From *1525* ft. to *1587* ft.

WATER SANDS.

From *797* ft. to *805* ft.	*Water stands at 600* ft.
From *1620* ft. to *1608* ft.	

METHOD OF SHUTTING OFF WATER.

12½ in. casing cemented at *1214* ft. with *31* sacks of *GG* (*12/3/13*) cement.
10 in. casing cemented at *1497* ft. with *56* sacks of *dumped in* (*12/24/13*) cement.
10 in. casing cemented at *1626* ft. with *73* sacks of *dumped in* (*4/29/14*) cement.
From -------- -------- -------- -------- --------

WATER TESTS.

(State how long cemented. Water level. Details of bailing and results.)

12½" casing. Practically no cement in casing. Cemented at 1214' (12/3/13). Set until 12/7. No record of any test.

10" casing cemented at 1497' with 56 sacks cement dumped in (12/24/13). Cement 10' in casing, but bailed out 5'. Let cement set to 3/16/14. Bailed hole dry, stood 6 hours and made no water. Drilled pocket to 1517', bailed hole dry, stood overnight and made 2 pails of water and a little oil.

10" casing cemented at 1626' with 73 sacks cement dumped in (4/29/14). Ran in and found cement 10' up in casing. Shut down for cement to set.

PERFORATIONS.

Machine From.	To.	Rows.	×	Holes per foot.	*See History.*
--------	--------	--------	---	--------	--------
--------	--------	--------	---	--------	--------

Gravity of oil *25.3* Water cut *0*	Initial rating of well *40 b/d*
Date well began prod. *Sept. 30, 1916.*	Heaving plug (material).
Remarks: (Special features not provided for above)	

At a depth of Feet

Drillers.

Harper, Brandle, Wheat.

technical identification, samples of each formation, carefully labeled with the depth from which they come, should be preserved in bottles for the use of the geologist.

As explained in earlier sections (see pages 189 and 356), modern coring tools afford means, in either churn drilling or rotary drilling, of securing undisturbed samples of the formations penetrated by the well. Inspection of core samples in the field and in the laboratory by geologists or engineers capable of identifying with accuracy the lithologic properties, fluid and fossil content of the formations cored will contribute greatly to the information incorporated in the log of the well. A later section (see page 667) describes the technic of inspecting and analyzing core samples.

WELL LOGS

Of the various records concerned with well data, none is more important than the log of the well. The log should give a complete history of the well from the time of its location until its abandonment. Every detail of the drilling procedure should be made a matter of record: the well equipment; the thickness, nature and depths of strata penetrated; depths at which oil, gas and water of special characteristics are encountered; depths at which casings are landed and water shutoffs made; water shutoff tests and names of witnesses; dates of starting and completion of drilling; names of drillers, tool dressers and others employed in the work; explosives used and depths at which used; results of formation and production tests; initial production of oil, gas and water; and rating after 30 days' production. Repair work, redrilling jobs, alterations and important replacements of the well equipment, work involved in abandonment, etc., should be added to the original drilling record from time to time as such work is performed.

These data should be arranged in chronological sequence except for the stratigraphic record, which should be maintained in a separate table arranged in depth sequence. It is customary to classify these data under several different headings for convenience in reference. We may have one section devoted to the location of the well, another to the stratigraphic record; one to the chronological record of the original drilling, another to subsequent history; and still other sections will be concerned with the casing record, depths of oil and gas sands, water sands and water shutoff methods and tests. The log form* given on pages 624 and 625 is typical.

Graphic Logs.—We may indicate much of this information with the aid of various conventional symbols on a graphic log, which is more

* After A. W. Ambrose, *U. S. Bur. Mines Bull.* **195.**

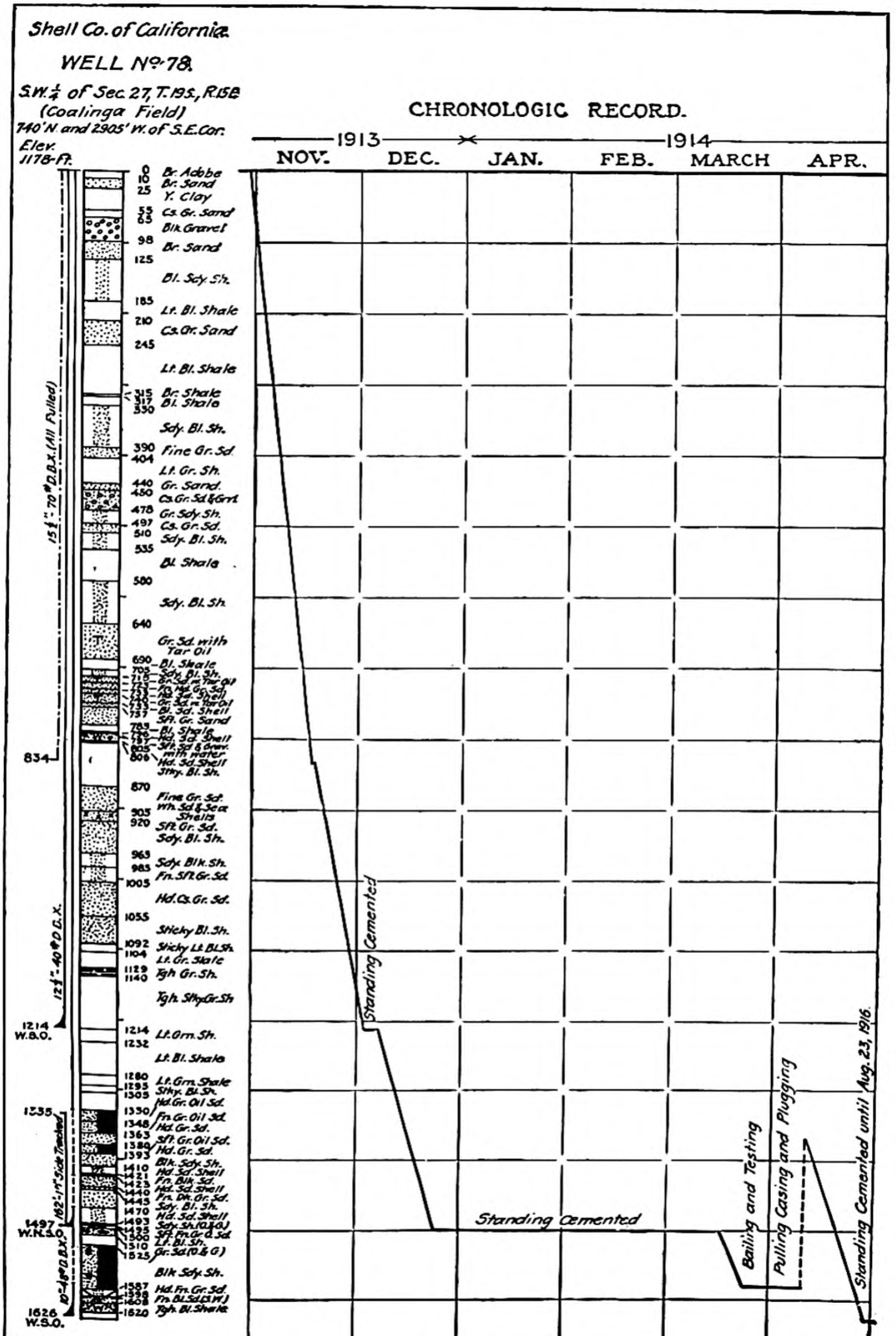


FIG. 265.—A typical graphic log with graphic chronological record.

desirable for certain purposes than the written historical record. Most operators will find it desirable to preserve the well record in both written and graphic form. The graphic record, plotted to vertical scale as illustrated in Fig. 265, is particularly valuable in that it conveys quite

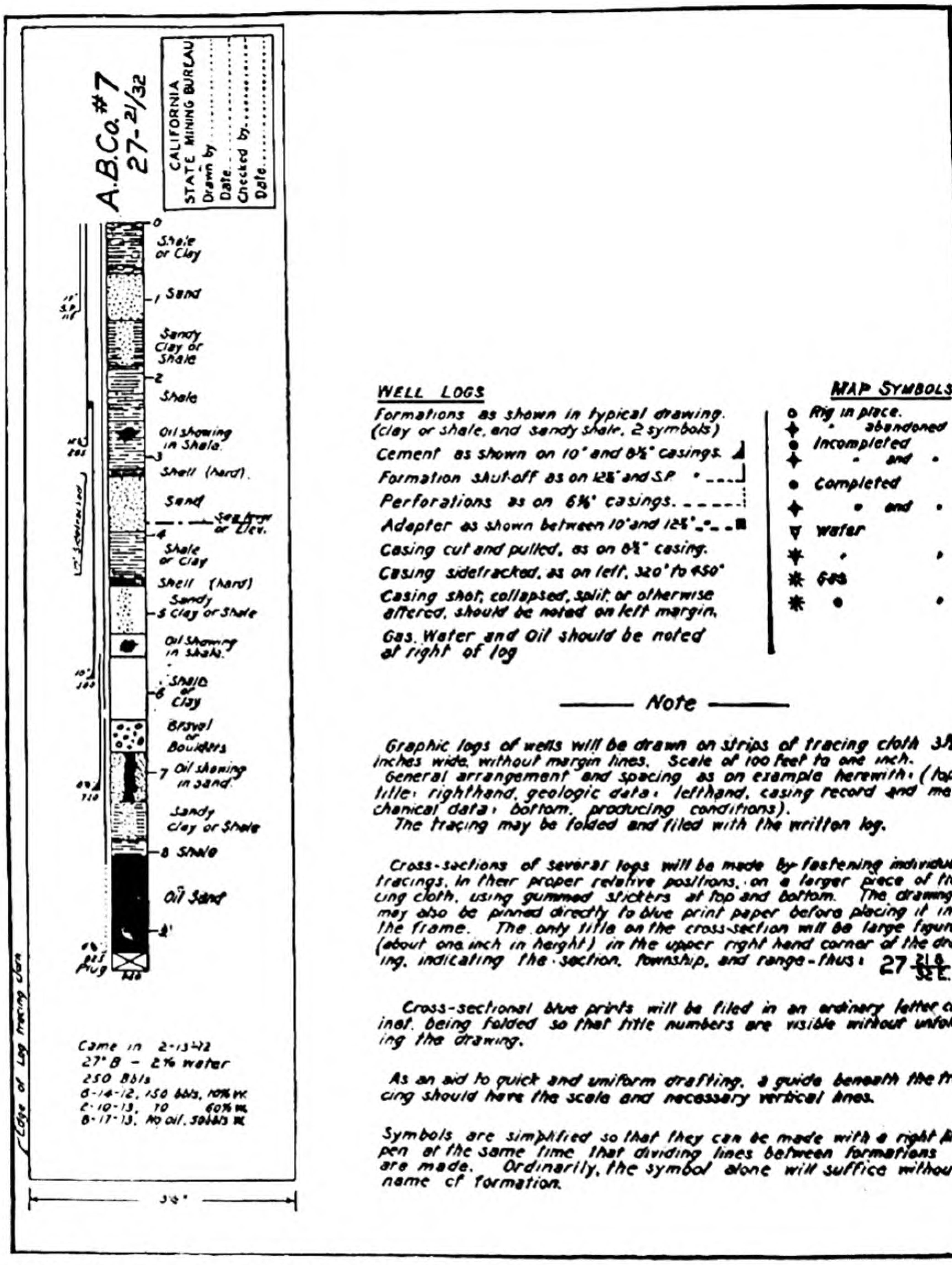


FIG. 266.—Conventional symbols for use on oil-field maps and well logs adopted by California State Mining Bureau, Department of Petroleum and Gas.

readily, by pictorial means, facts which can only with difficulty be made strikingly apparent in the ordinary form of written record. For example, it conveys a true impression of relative depths, thicknesses of strata encountered in the well and their sequence and indicates the manner in which the well is cased to better advantage than is possible in the written

record. There are no conventional well-log symbols that are yet recognized as standard, but those suggested in Fig. 266 have been adopted by the State Mining Bureau of California and have found wide appplication in drilling records in that state. The author has compiled the somewhat more complete group of conventional symbols given in Fig. 267 from several sources.

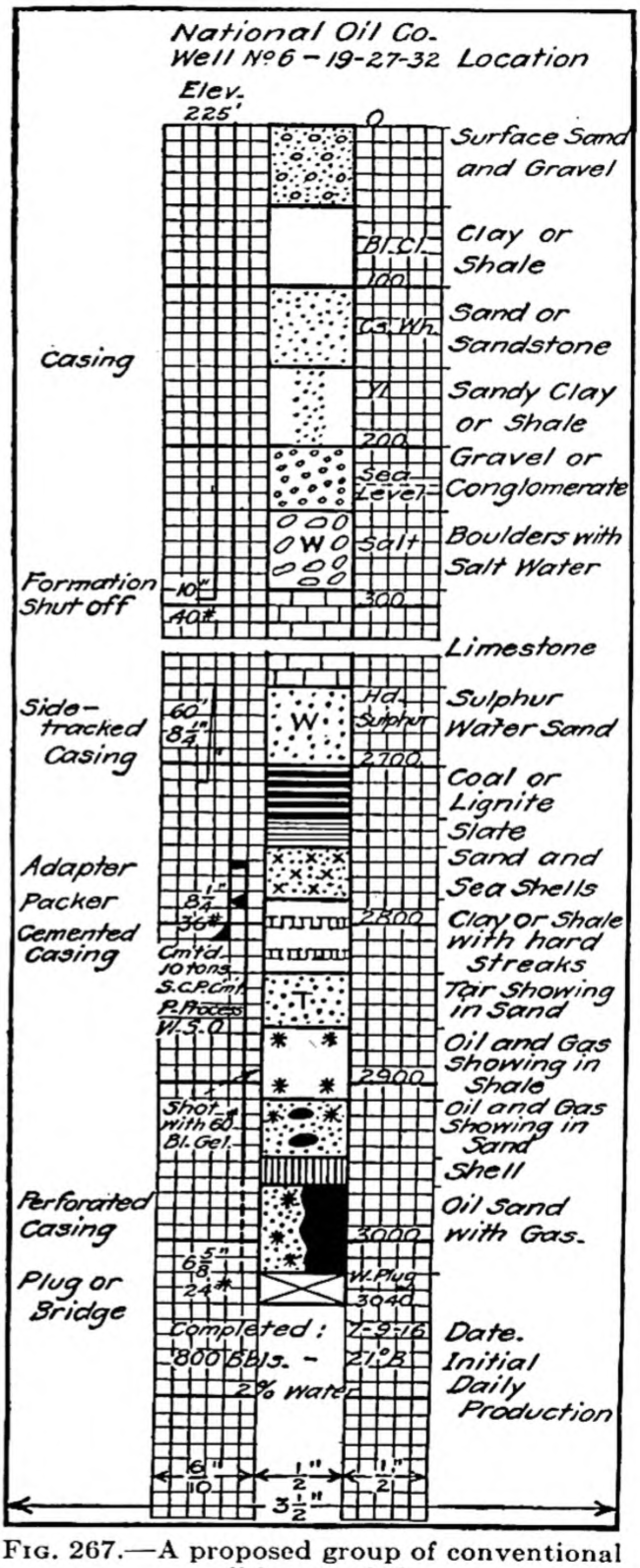


Fig. 267.—A proposed group of conventional well-log symbols.

In selecting symbols for use on well logs, considerable time and expense may be saved by using simple forms that can be readily applied. They should, however, be sufficiently distinctive so that no confusion in interpreting them will result. Predominating rocks, such as shale or sandstone, may be left blank. Rock colors may be indicated in connection with the conventional forms representing different types of rocks, by the use of suitable abbreviations. The fluid content of the formation penetrated—either oil, gas or water—must also be indicated at the proper scale depths. Oil may be represented by solid black applied over the entire stratum in which it occurs, if present in quantity, or in irregular patches on the formation graph if only slight "shows" are in evidence. Water and gas are conveniently indicated by their initial letters placed at one side of the stratigraphic record. It is customary to indicate the depths to the top and bottom of all oil and gas sands, as well as important marker horizons and reference points, by the use of small figures placed at one side of the formation record.

The casing record forms an important part of the graphic log. This usually consists of a series of vertical lines about ⅛ in. apart, placed at one side of the stratigraphic record, one line being drawn for each string of casing placed in the well. The landing depths should be indicated by terminating each vertical line at the proper depth with reference to the scale used for the stratigraphic record. A short horizontal line at this point emphasizes it more definitely, and the

length and diameter of casing should be lettered along it. When a string of pipe has been cemented, a free-hand fillet of sufficient weight to attract the attention may be applied in the angle formed by the horizontal and vertical lines (see Fig. 267). If tests show that water has been successfully excluded by the cement, the abbreviation W.S.O. (water shutoff) may be added, or W.N.S.O. if unsuccessful. Perforated casing or screen pipe can be indicated by dotted or dashed lines.

Brief notes descriptive of the drilling operations, the results obtained and interpretations of data should be freely used, lettering them at the proper point opposite the stratigraphic record. At the top of the graphic log should be lettered the well number, its location, elevation of the floor of the derrick and date of starting. At the bottom should appear the final depth, date of completion and the rating of the well, or its initial production of oil, gas and water. The gravity of the oil should also be given.

Graphic well logs may conveniently be constructed on strips of tracing cloth 3 in. wide and long enough to permit of plotting the entire record on a scale of 1 in. to 100 ft. This scale is large enough to show a 2- or 3-ft. stratum. Tracing cloth on which is printed a 10- by 10-in. cross-section grid is convenient, permitting the log to be constructed without the aid of a scale. However, the coordinate lines obscure to some extent the conventional symbols used. By working on the reverse side of the cloth from that on which the coordinate lines are printed, and removing the latter with alcohol or chloroform when the drawing is completed, this difficulty can be overcome. Some draftsmen prefer to use plain tracing cloth, plotting the log over a specially prepared standard form ruled with horizontal lines 1/10 in. apart, which may be slipped under the tracing cloth before the work is begun. Every 100-ft. interval should be indicated in this case for convenience in reference.

Blueprinted copies of the logs are quickly made from the tracings when desired. A more pleasing result is obtained by making brown-process prints from the tracings, these being used in turn to make blue-line or positive blueprints; or brown-process paper may also be used in making the positive prints, securing a black-line print closely resembling the original drawing. The black-line or blue-line print may be tinted, if desired, with the aid of water color or crayon, a process which greatly enhances the final appearance of the logs and gives opportunity for the use of distinctive conventional colors.

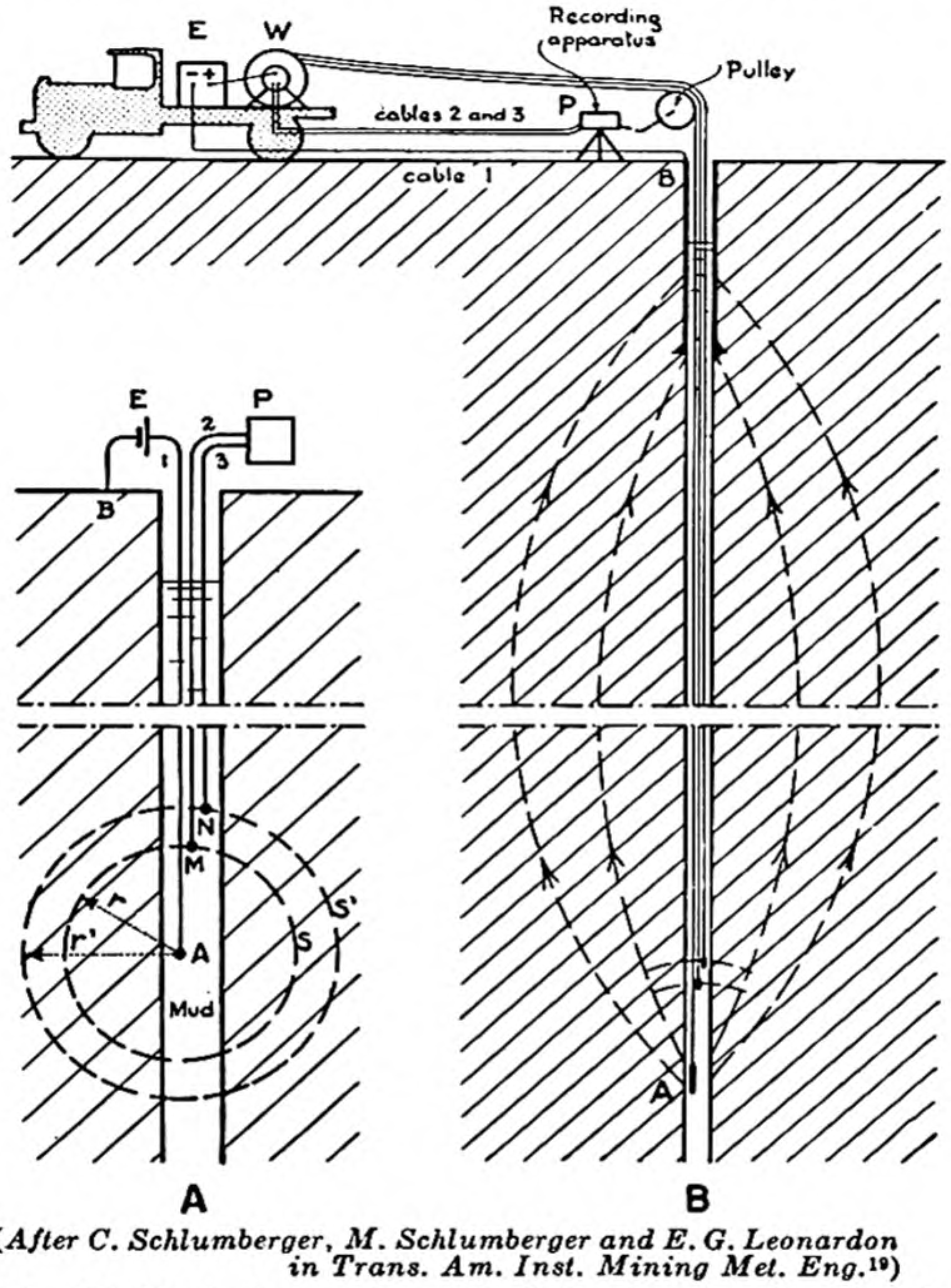
ELECTRICAL LOGGING OF WELLS

A method of determining the lithologic character of the formations exposed in the wall of a well and their fluid content, without cutting samples of the material or removing any of it to the surface for inspection, involves measurement of the electrical resistivity, electrofiltration and electroosmosis properties of the rock masses as they exist in place. First developed and applied by Conrad Schlumberger, a French geophysicist, and his coworkers in the oil fields of Russia, Venezuela and Rumania in 1929–1931, the method was introduced into the oil fields of the United States in 1932 and has since been widely employed. In some regions, upward of 90 per cent of the wells drilled are surveyed by this means. Electrical logging may be regarded as an outgrowth of earlier methods of geophysical exploration involving surface studies of earth resistivity.

Resistivity Measurements.—Though most rock minerals are poor conductors of electricity, sedimentary formations usually contain water

in their pore spaces, frequently saline water, which renders them conductive for electricity in varying degree. The greater the amount of moisture and the greater the amount of dissolved electrolytes in the water, the greater the conductivity of the containing rock masses.

In comparing the electrical properties of rock strata exposed in the wall of a well, a system of electrodes lowered into the well from the surface on a multiconductor cable is employed as a means of establishing a flow of electricity into each stratum while the relative conductivities of



(*After C. Schlumberger, M. Schlumberger and E. G. Leonardon in Trans. Am. Inst. Mining Met. Eng.*[19])

FIG. 268.—Method of securing resistivity logs in electrical logging.

different beds are determined by measuring the inverse values or their relative resistivities. Figure 268*A* illustrates diagrammatically a commonly used method of measuring relative resistivities of different strata. A flexible cable, containing three insulated conductors, is lowered into the well, each conductor supporting at different depths an electrode, *A*, *M* or *N*. The well is filled with conductive water or drilling fluid and there must be no casing in the interval where observations are to be made. The lowermost electrode *A* is used as a means of passing an electric current through the well fluid into the surrounding stratum. The conductor on which it is suspended is connected at the surface with the positive pole

of a storage battery or other source of direct current E, while the negative pole is grounded near by at point B—often on the surface string of casing or in the mud pit. An electrical field is thus established about electrode A as a center, which in homogeneous material would develop equipotential spheres of radius r and r', respectively equal to distances AM and AN between the several electrodes. Distances AM and AN must be large in comparison with the diameter of the well—perhaps ten to twenty times greater. Conductors 2 and 3, supporting electrodes M and N, are connected at the surface through a potentiometer P, which indicates the difference in potential between M and N. This potential difference is a measure of the average resistivity of the earth formation surrounding the electrodes.[19]

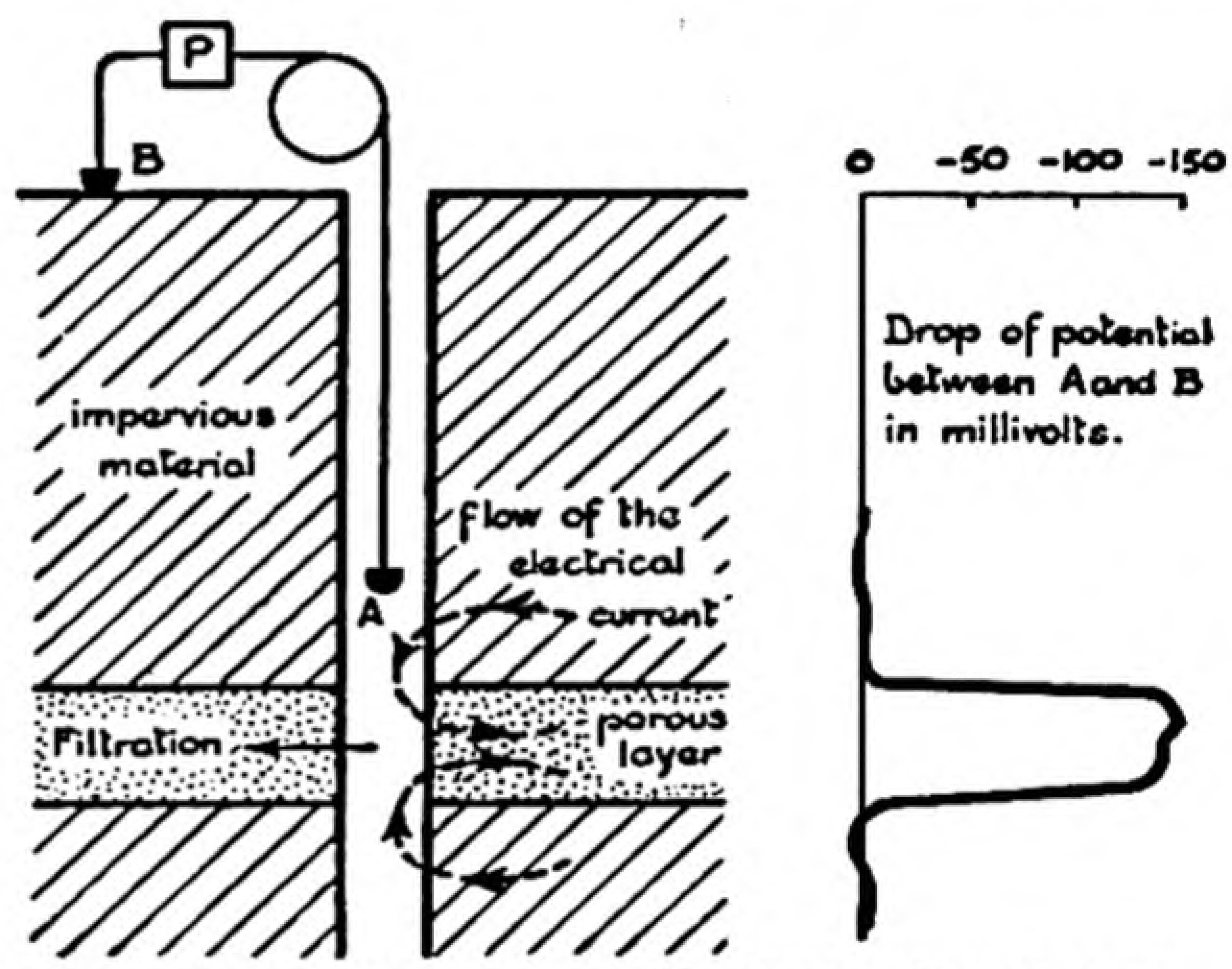
Figure 268B illustrates in a more practical way the arrangements at a well for conducting a resistivity survey and the theoretical paths of the electrical current through the earth from electrode A to ground B. The three-conductor insulated cable supporting the electrode system is wound on winch W, which is mounted on the bed of a motor truck, and is of sufficient length to extend down into the well through the full depth of the formational interval to be surveyed. The electrode system is slowly lowered into the well and a continuous record showing variation in resistivity, as indicated on the potentiometer, is automatically recorded on photographic film in the form of a profile on a depth scale that can be directly compared with a graphic drillers' log of the well. Values of resistivity are expressed in ohms per cubic meter of rock mass and range from as little as one ohm to several thousand ohms, depending upon the electrical conductivity of the material.

A variety of factors influence the magnitude of the resistivity recorded. If a rock stratum is very compact and contains little moisture, or if the water that is present contains little dissolved salt, the indicated resistivity will be high. Dense masses of hard rocks like granite, quartzite, gneiss, or marble, and softer rocks containing but little connate water, such as gypsum, rock salt, or coal, customarily have high resistivities. Unconsolidated and semiconsolidated formations, consisting of clays, shales, marls, sands, sandstones, etc., generally contain much water in their interstices—often saline water—and therefore normally possess low resistivities. On the other hand, if nonconductive oil or gas is present in the rock pores instead of water, the observed resistivity will be high. In such rocks, the observed resistivity may thus characterize the nature of the fluid confined in the pore spaces of the rock, as well as the lithologic properties.

Inasmuch as the electric current must flow through the well fluid to reach the wall rocks or the electrodes, it is clear that the conductivity of the fluid in the well will greatly influence the observed resistivity.

If the well fluid is salty, it will be more conductive and the resistivity will be lower than when the current must flow through fresh water. The spacing between the electrodes determines the depth of investigation, which in practical work varies from 3 to 10 ft. If drilling fluid has penetrated the walls of the well for several feet, as may be the case in drilling through permeable beds, close spacing of the electrodes may show quite a different resistivity profile than when the electrodes are widely spaced. The extent to which drilling fluid penetrates the walls of the well will depend upon the differential pressure between the fluid in the well and that in the formation. Ordinarily this differential pressure increases with depth, so that resistivity measurements taken at shallow depths are not quantitatively comparable with observations at greater depths. Increase in temperature decreases the resistivity and since the earth temperature increases with depth, it follows that the observed values of resistivity in comparable materials become smaller as depth below the earth's surface increases.[20]

Spontaneous Electrical Phenomena in Wells.—If a single electrode A, suspended on an insulated conductor cable, is lowered into a well and the other end of the conductor is grounded as shown diagrammatically in Fig. 269, a potentiometer P, in the circuit, will disclose a measurable potential which is found to vary with the permeability of the formation surrounding the electrode in the well. No electricity from any extraneous source is imposed. This so-called "self-potential" may range as high as 300 millivolts. The spontaneous electromotive force (e.m.f.) thus observed is believed to develop as a result of two simultaneously operative phenomena called "electrofiltration" and "electroosmosis."



(*After C. Schlumberger, M. Schlumberger and E. G. Leonardon in Trans., Am. Inst. Mining Met. Eng.*[19])

FIG. 269.—Method of observing spontaneous potential of formations penetrated by a well.

When a liquid is forced through a porous medium, a difference in potential between two points in the porous solid is observed. Thus, drilling fluid filtering through the porous rock strata exposed in the wall of a well develops an electrofiltration effect which creates an e.m.f. that may be measured by the single-electrode circuit described. Also, an e.m.f. is generated whenever two different electrolytes come into contact in a porous medium: as when drilling fluid enters a permeable stratum from the well and develops contact with the native fluid in the

formation. The e.m.f. developed increases as the interfacial surfaces of the fluids in contact increases, and inasmuch as this interfacial surface of contact increases with the depth of penetration of the drilling fluid into the formation, it follows that a greater electroosmosis effect is developed in highly permeable strata than in those less so.[16]

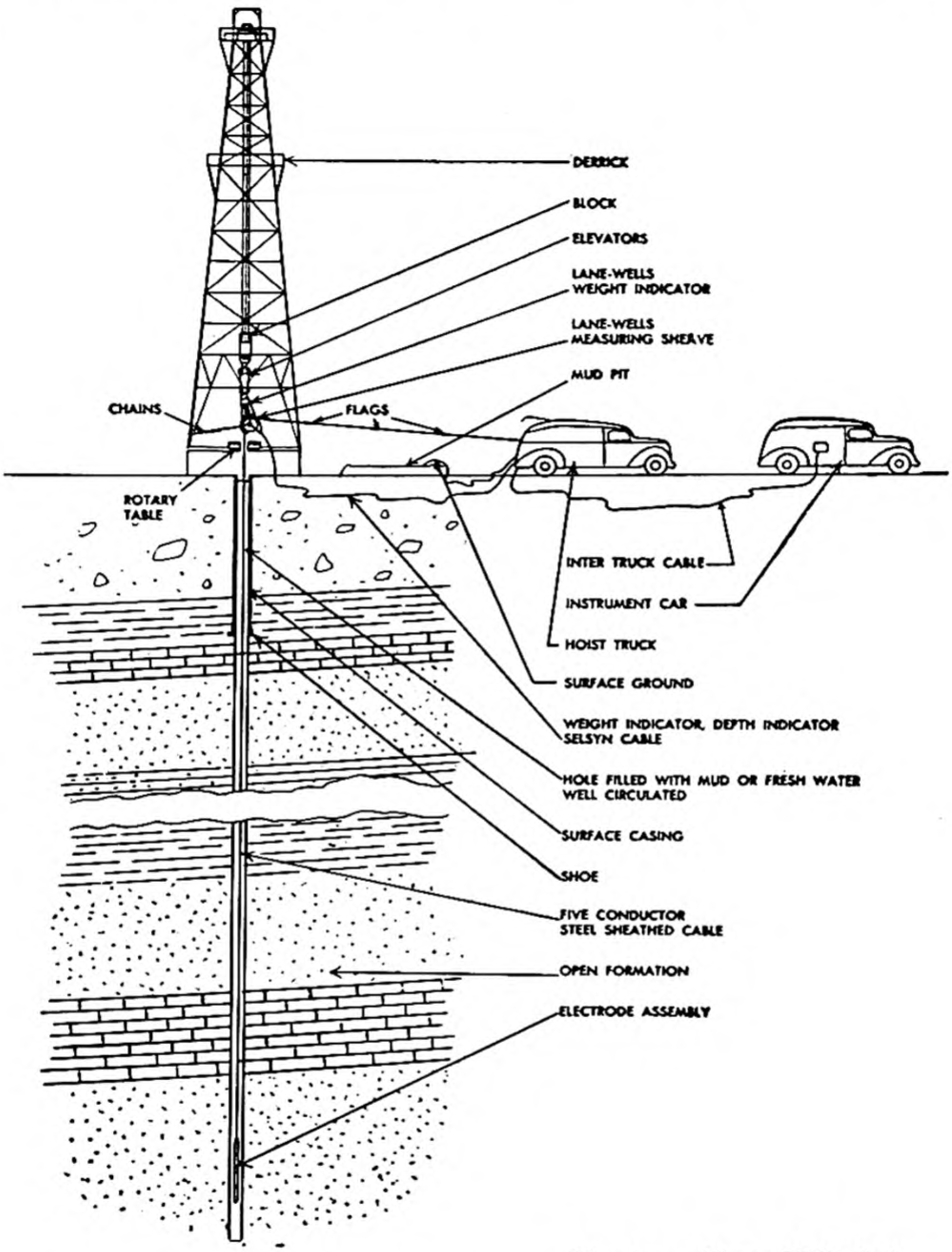
Ordinarily, drilling fluid flows from the well into the formation and the formational fluid is saltier than the well fluid. Under these circumstances, both electrofiltration and electroosmosis phenomena tend to develop a negative anomaly at the wall of the well, and resulting self-potentials are additive. This, however, is not necessarily the case, for either condition may be reversed and independently of the other. Hence, under abnormal circumstances, both may develop a positive anomaly at the wall of the well, or one may be positive and the other negative. In the latter case, the net self-induced e.m.f. will be equal to the difference between the electrofiltration e.m.f. and the electroosmosis e.m.f. Inasmuch as both result from migration of drilling fluid into the wall rocks and such migration occurs more readily and to a greater extent in highly permeable strata than in those less so, it follows that the observed values of the self-potential generated become a measure of the relative permeabilities of the formations which give rise to them.

In recording the self-potential diagram of formations intersected by a well, one of the electrodes in the multielectrode system employed in making resistivity measurements is so connected with recording instruments at the surface that as the electrode system traverses the well, a continuous graph is automatically recorded against a depth scale on photographic film. This profile shows relative values of the e.m.f. generated opposite each stratum in the interval surveyed. The self-potential diagram was originally called the "porosity log," in the belief that the observed anomalies were proportional to formation porosity; but the e.m.f. generated is primarily responsive to variations in permeability, and such a profile is more properly called a "permeability log."

Most of the factors that influence the magnitude of resistivity measurements also influence self-potential measurements. The salinity of the fluid in the well in comparison with that in the formation, the differential pressure between the well and the formation, and the temperature—all have their effect. In addition, the viscosity of the well fluid will influence the rate of penetration of the wall rocks and hence influences the observed potential, the two factors being inversely proportional. The density of the drilling fluid determines the differential pressure between the well and the formation and thus tends to influence the observed e.m.f. Self-potential values normally increase with depth, owing to the greater excess of pressure of the well fluid over that of the formational fluids with increasing depth. However, temperature

increases with depth and increases the fluid conductivity, thus tending to reduce the self-potential.[13]

Equipment Employed in Electrical Logging.—Successful electrical logging requires specially designed equipment and highly skilled technical personnel. The methods



(*Courtesy of Lane-Wells Co.*)

FIG. 270.—Arrangement of equipment used in electrical logging.

and apparatus used are patented and licensed for use only to certain service organizations that make a business of conducting electrical surveys on a fee basis. Two service organizations are especially well known for their work in this field, these being the Schlumberger Well Surveying Corporation and the Lane-Wells Company, the latter exploiting equipment known to the industry as the Geoanalyzer. Both of these concerns maintain equipment and personnel in all of the more active oil-producing regions of the United States and are ready to respond to any call for their services on

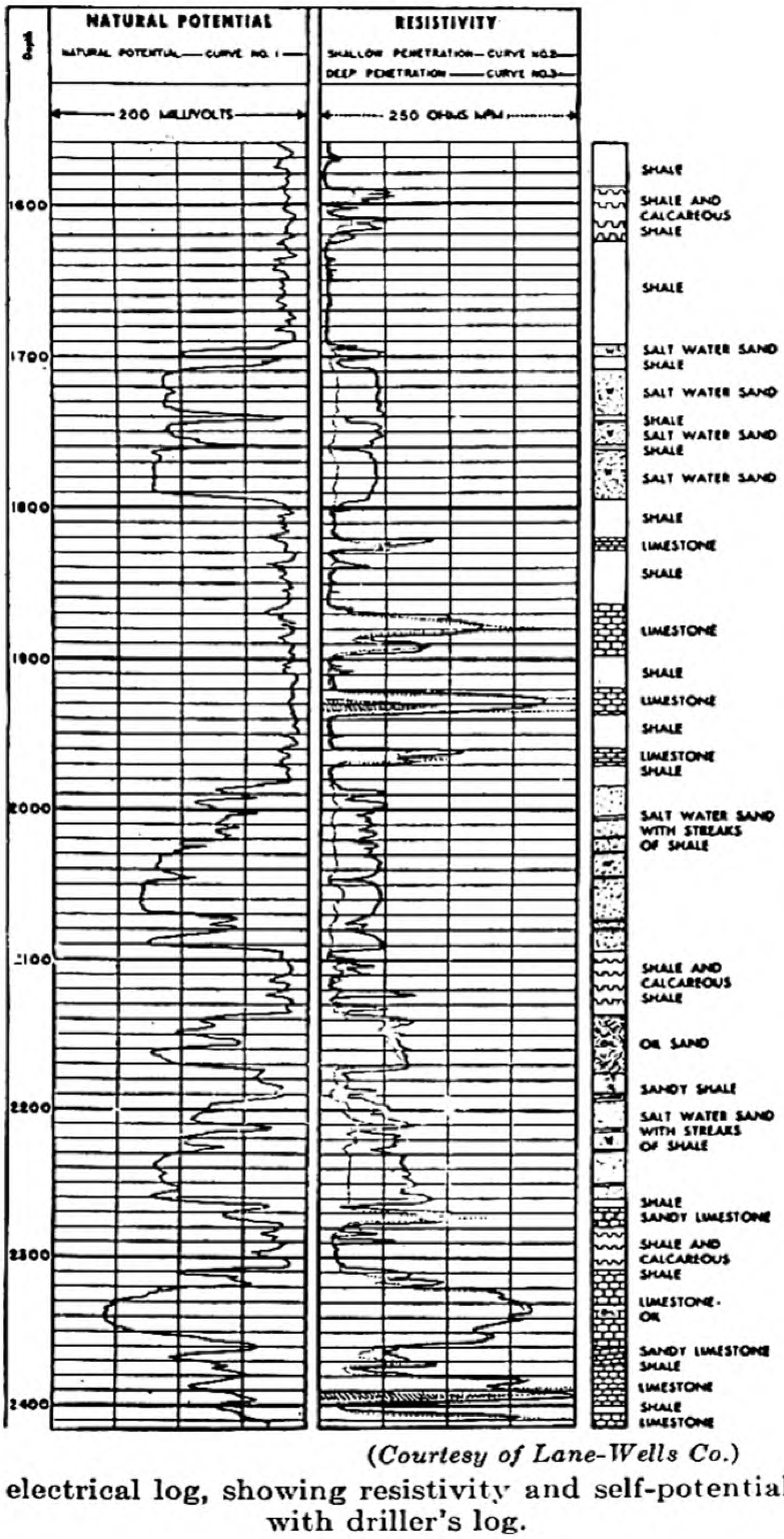
short notice. The same equipment and personnel are also available to undertake gun perforating of casing (see page 572) and the two services are frequently combined. Utilizing, in part, the same equipment used in electrical logging, the Schlumberger Corporation is also equipped to make temperature surveys, formational dip surveys, geophone surveys, and accurate depth determinations. The same equipment is also employed in securing side-wall samples of the formations exposed in the wall of the well.

Figure 270 pictures automotive equipment employed by the Lane-Wells Company. A heavy motor truck equipped with a winch carries the multiconductor cable which, on the larger outfits, is 15,000 ft. long. A second "panel truck" carries the electrical and mechanical recording equipment and photographic apparatus. The electrical equipment, by means of which direct current is generated and transmitted into the well, consists of a motor-generator set, with controls that permit a wide range of voltage. After traversing the formations about the well, the electrical impulses are picked up by the receiving electrodes and transmitted back to the surface through the multiconductor cable; their amplitude is measured by three meters, the variations in readings on which correspond to variations in electrical characteristics of the formations tested. A beam of light is reflected from a mirror mounted on the indicating element of each of these meters, and these light beams are so directed as to record each minute variation in the amplitude of the meter indicators on a moving strip of sensitized film as the electrode system traverses the well. Three profiles are thus recorded simultaneously on the same film: two resistivity profiles and the self-potential profile. The apparatus permits of constant observation of the recording process by the operator. Movement of the sensitized film past the light beams is synchronized by a gear mechanism with the vertical movement of the cable in the well. Either of three depth scales may be used: 1 in. to 20 ft., 1 in. to 50 ft. or 1 in. to 100 ft. Another mechanism prints on the moving film the reference coordinates, scales and depth figures. The electrode system traverses the well at a rate of from 100 to 150 ft. per min. The panel truck also carries photographic developing and fixing tanks so that the primary record can be completed and examined at the well. Later, prints are made on sensitized paper from the primary film record. The film record may be secured in from 1 to 3 hr. at the well.

Character of Records Secured in Electrical Logging.—Figure 271 is illustrative of the usual type of record furnished by the electrical-logging service organizations. On a depth scale of 1 in. to 50 ft., the record strip is about 7 in. wide and of whatever length may be necessary to display the interval logged on the scale employed. It will be noted that the upper part of the record gives all necessary identifying data and such other information as will be necessary for proper interpretation. The right side of the record displays two separate resistivity logs (one a solid-line profile and the other dotted), while the left side gives the "porosity log" or "self-potential" or "natural potential" profile. The resistivity log that appears as a dotted profile is one made with wider spacing of the electrodes and represents a record of greater lateral depth of investigation than the solid-line resistivity profile. The latter represents a penetration of about 3 ft., while the dotted, so-called "second curve," represents a depth of investigation of about 6 ft. If necessary, a third resistivity profile representing a depth of investigation of about 10 ft. may be provided. These additional resistivity profiles are helpful in cases where drilling fluid has invaded the wall rocks to a depth of several feet and the normal spacing of electrodes does not differentiate satisfactorily between the various strata comprising the interval surveyed.[24]

Interpretation of Electrical Logs.—From the foregoing discussion of the theoretical aspects of electrical logging, it will be appreciated that

electrical logs represent the composite effect of many different complex variables and that a complete interpretation of the record would require careful consideration of the influence of each of these factors and of the fundamental nature of the process by which the record is secured.



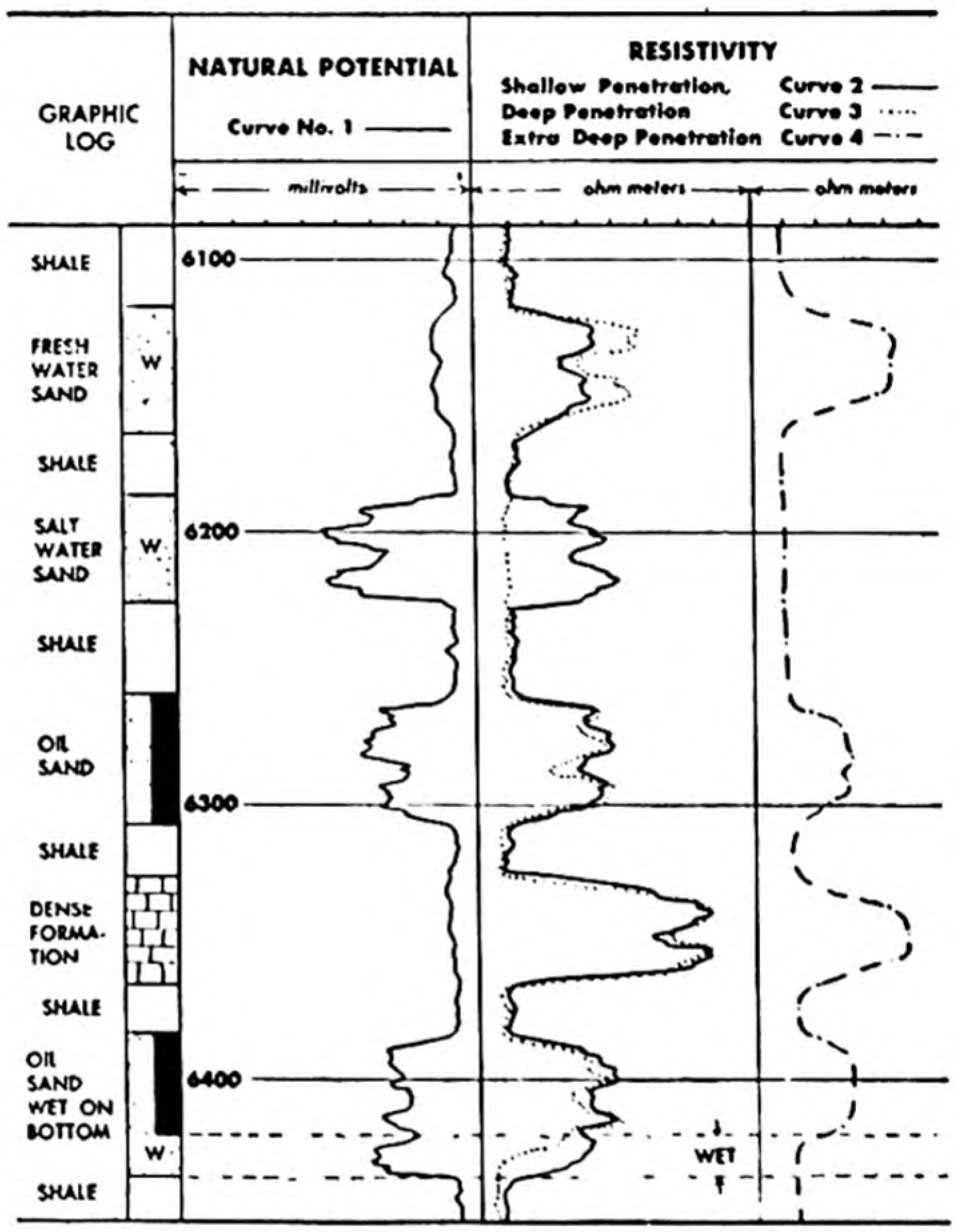
(*Courtesy of Lane-Wells Co.*)

Fig. 271.—Typical electrical log, showing resistivity and self-potential profiles correlated with driller's log.

Complete interpretation of the record should be entrusted to engineers skilled in this work, yet certain elementary characteristics of these logs are so apparent that even the novice may profit by inspection of them.

With the knowledge that variations in resistivity are responsive primarily to the fluid content of rock strata and that variations in self-

potential voltage are responsive primarily to changes in the permeability of strata, we may, by observing the character of these two parameters, make broad conclusions concerning the lithologic character of the strata, their thickness and fluid content. A high resistivity value is usually indicative of the presence of oil, gas, fresh water or sulphur water at the horizon logged; a low resistivity value ordinarily means salt water. A high voltage on the self-potential profile is characteristic of a highly permeable stratum; a low voltage is indicative of an impermeable material. Figure 272 shows diagrammatically the characteristic appear-



(Courtesy of Lane-Wells Co.)

FIG. 272.—Characteristic appearance of electrical logs for various common occurrences.

ance of the resistivity and self-potential profiles for different occurrences commonly encountered in drilling in oil-producing regions. If there are marked changes in the character of strata as between, say, an oil sand and the underlying and overlying shales, it is often possible to determine with considerable accuracy, the thickness of the productive stratum and also that portion of it which contains and will yield the most oil.

If we are seeking commercially productive oil and gas sands, we should be interested in any stratum of reasonable thickness that on an electrical log develops a high resistivity value and a high self-potential value, these indications being characteristic of permeable strata containing oil or gas. However, it must be emphasized that these character-

istics may be influenced by many other factors and that the indications mentioned, although they are usually dependable, are not an infallible guide. Detailed study of the profiles by a person skilled in their interpretation, and familiar with all of the circumstances surrounding the survey, may be necessary for an intelligent appraisal of the result. For example, a sand or sandstone that is free of clay, silt, volcanic ash and other fine-textured materials should be highly resistive if it contains oil or gas in its pore spaces. An oil-bearing shaly sand, on the other hand, is likely to contain considerable connate water, usually salt water, and though oil may be present in abundance and the indicated permeability may be high, yet the presence of conductive salt water may prevent the resistivity profile from attaining the form generally regarded as characteristic of commercially productive oil sands. Fine-grained oil sands generally contain more connate water than coarse sands and hence are less resistive. A gas-bearing stratum should contain less connate water than an oil-bearing stratum, and hence should display higher resistivity. On the other hand, gas-bearing sands are more readily invaded by drilling fluid than oil sands and, if the drilling fluid contains dissolved salts, gas sands may appear less resistive than oil sands. A resistivity profile of greater depth penetration should be helpful in disclosing this condition. Distinction between oil and gas sands is usually difficult unless a temperature survey is combined with the electrical survey (see page 655). If gas is present in a stratum penetrated by a well and is allowed to flow into the well sufficiently to permit local gas expansion at the wall of the well, the temperature survey will disclose a lower than normal temperature where the well pentrates the gas-bearing stratum. Beds of solid salt, limestone or well-cemented sandstone often develop high resistivity because, being dense and nonporous, they contain little or no connate water. However, they would not ordinarily be confused with oil or gas sands because their indicated permeability on the self-potential profile would be low.[11]

Application of Electrical Logs.—As suggested in the foregoing paragraph, one of the most important applications of electrical logs is that of indicating the lithologic character, thickness and fluid content of strata penetrated by the well, thus affording a means of identifying all oil, gas and water-bearing sands and of estimating the possibility of securing commercial production from them. Ability to classify strata penetrated by the wells in a field as oil sands, gas sands, water sands or shale bodies, and to indicate their relative productive capacities, is of great value to one planning the casing and completion program of a well in process of drilling. On the basis of such information, arrangements may be made to cement off all water-yielding beds behind blank casing and to perforate the oil string opposite potential oil- and gas-producing strata. In some fields where the oil-producing strata must be shot with explosives to stimulate production, electrical logs have been helpful in determining the exact depths at which to place the explosives. If for any reason it should be desired to case off certain potential producing horizons when a well is first completed

and placed on production, the electrical logs will show at any future time when it may be desired to produce from them just where the casing must be perforated to reopen such excluded oil or gas sands. In many cases, electrical logs have disclosed the presence of minor oil sands that were not made known by any other indication in the routine of drilling and testing.*

Another very important application of electrical logs is their use in correlation of strata from well to well, and in the use of such correlations in interpreting geologic structure. A certain sequence of strata will often develop a peculiar pattern in the resistivity and self-potential profiles that is characteristic of a particular interval. Often such patterns can be recognized in the logs of different wells in the same locality, so that by reference to them correlations of formations from well to well may be made with confidence. Often some particular stratum exhibits an abnormally high resistivity or self-potential value which will serve to identify it in the section. In fields where electrical logs have been made in many wells, certain electrical markers are recognizable in almost every log and come to be known by particular name, letter or number designations. Thus, the Schlumberger J marker is apparent in almost every electrical log of the Temblor producing interval in the Kettleman Hills North Dome field of California—an area of some 18,000 acres—and engineers and geologists familiar with the field have come to know this marker as one of the dependable stratigraphic reference horizons.

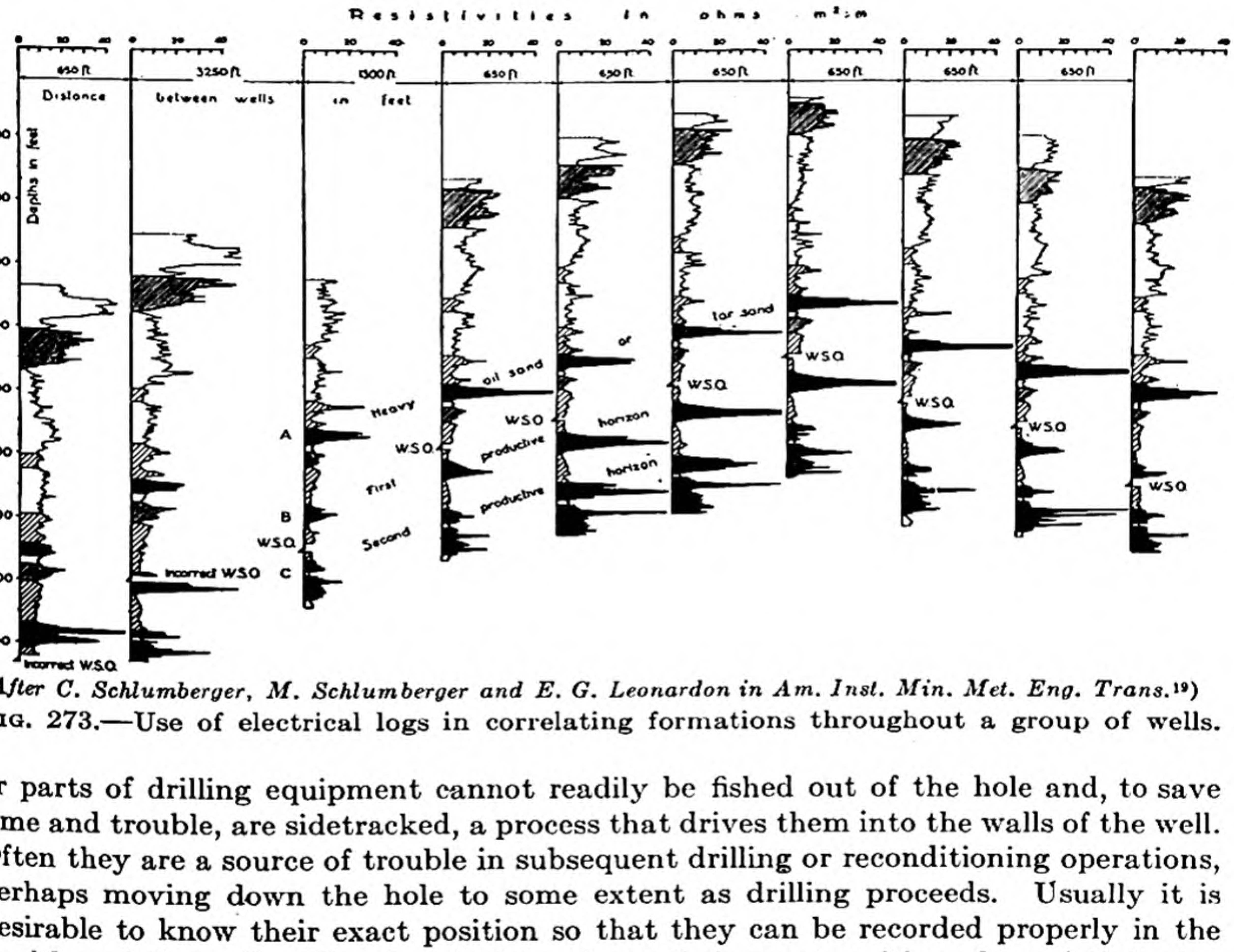
Electrical markers have proved to be the most dependable basis for correlation in many fields. In thick formations containing many individual reservoir sands, it is helpful in tracing the continuity of beds to have reference markers that can be identified within the oil-producing zone. In the thick producing formations of certain of the California fields, for example, aggregating perhaps many hundreds of feet in thickness and composed of closely interstratified beds of sand and shale, some strata are more prolific producers than others, and it is important to have a means of recognizing these in drilling the wells, in order that perforated pipe may be set properly and in order that a systematic plan of drainage may be carried out. Often water-yielding strata are so intimately related to the oil- and gas-bearing sands that very precise information of their depths and thicknesses must be had before they can properly be sealed off. For such purposes, a dependable basis for correlation and identification of particular strata, or groups of strata in each well drilled, will be of great value.

Ability to correlate formations from well to well with certainty greatly facilitates interpretation of geologic structure—a problem of importance in the early development of every oil field. Figure 273 shows a typical case in which a series of 10 resistivity logs, in a section transverse to the axis of an anticlinal fold, discloses the continuity of three oil-bearing zones and indicates the dip of strata on each flank of the structure. The illustration also indicates how such logs may be of assistance in determining the proper point for the water shutoff (W.S.O.) between the upper tar sand and the first producing horizon. Location of faults intersecting strata between wells is often clearly disclosed by correlation of electrical logs. The existence of a fault is indicated by a missing interval in one log that is clearly apparent in the log of another near-by well. Close study of a series of electrical logs will usually reveal the course of a fault plane across a field, or lenticular conditions that result in variation in thickness of beds in different areas within the field. Detailed and accurate tectonic studies are greatly facilitated in fields where a sufficient number of electrical logs are available.

* Uren, L. C., Electrical Logging to Determine Character of Formations, *Petroleum Engr.*, December, 1942, pp. 46–56.

One of the several methods of estimating the amount of oil in an oil field involves estimating the thickness, porosity and oil saturation of the producing strata. From such information, we may compute the storage space available in the formation for storage of oil, and thus estimate the gross amount of oil available. Often the actual thickness of the oil-yielding formation is somewhat uncertain, as the drillers' logs do not usually give sufficiently accurate and dependable information. The electrical logs afford data that indicate with fair accuracy, the thickness of the oil-yielding beds and, in a qualitative sense, comparative permeabilities of different portions of the producing formation. The latter factor enters in estimating the probable percentage recovery and rate of recovery. In conjunction with pressure observations, it may also assist the engineer in predicting initial productions of wells.

In the drilling of wells, difficulties occasionally arise which result in detachment or breakage of tools or parting of casings. Often these detached sections of pipe



(*After C. Schlumberger, M. Schlumberger and E. G. Leonardon in Am. Inst. Min. Met. Eng. Trans.*[19])
FIG. 273.—Use of electrical logs in correlating formations throughout a group of wells.

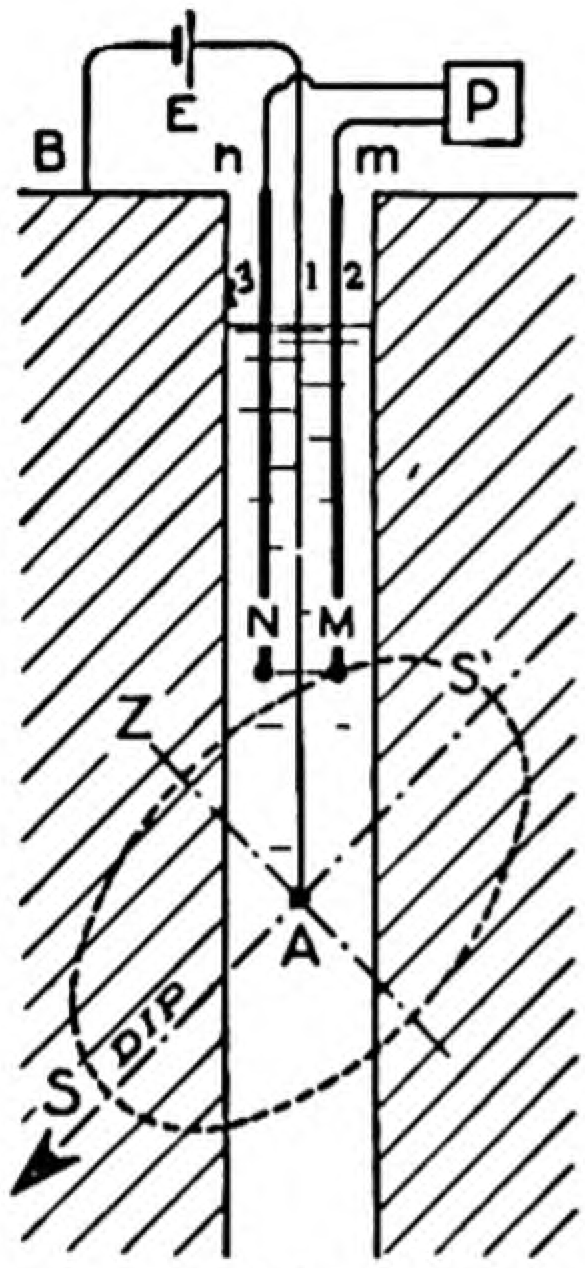
or parts of drilling equipment cannot readily be fished out of the hole and, to save time and trouble, are sidetracked, a process that drives them into the walls of the well. Often they are a source of trouble in subsequent drilling or reconditioning operations, perhaps moving down the hole to some extent as drilling proceeds. Usually it is desirable to know their exact position so that they can be recorded properly in the final log of the well. The electrical log shows their exact position, the resistivity log displaying abnormally low values when near metallic objects.

The exact position of the lower end of a column of casing in a well is sometimes a matter of uncertainty, even though the casing extends to the surface and measurements have been made as it is inserted. Because of crookedness of the hole, the lower end of the column may actually be at some structurally higher point than the length of the column might lead one to expect. The electrical log shows precisely the point at which the apparatus emerges from the casing and enters the open, uncased hole below.

Determination of Dip of Strata in a Well by Resistivity Observations.—Resistivity observations may be used as a means of estimating the amount and direction

of dip of strata exposed in the wall of a well. Such information is often important in oil-field exploitation, particularly in the early stages of development when there is, perhaps, only one completed well and the question arises as to proper location of the second and succeeding wells. The operator is anxious to keep his early wells "on structure" and to drill in locations that will tap the producing formation at structurally high points. By so doing, the possibility of drilling a dry hole is minimized. Knowledge of the dip of the formations may thus be of considerable assistance in forecasting the trend of the structure and indicating the directions from a discovery well in which other successful wells may be drilled.

Stratified rocks offer less resistance to the flow of electricity in the direction of the bedding planes—that is, in the plane of the dip of the beds—than in other directions. If an electrode is lowered into a well to a point opposite a stratum that dips at some angle from the horizontal, and a flow of current is established from the electrode into the formation, the equipotential surfaces established about the electrode are ellipsoids rather than spheres, and their axis of revolution is perpendicular to the dip plane. The Dipmeter, an instrument developed by the Schlumberger Well Surveying Corporation, utilizes this principle as a means of determining the direction and amount of dip of strata penetrated at depth in a well.



(*After C. Schlumberger, M. Schlumberger and E. G. Leonardon in Am. Inst. Min. Met. Eng. Trans.*[18])

FIG. 274.—Method of utilizing resistivity observations in determining dip of formations penetrated by a well.

The operating principle of the Dipmeter may be demonstrated by reference to Fig. 274. An electrical current from a source *E* is established through grounded electrode *A* and surface ground *B*, which are connected by an insulated cable, 1. As indicated in the sketch, the equipotential surfaces in the neighborhood of *A* are flattened ellipsoids, such as *S-S'*, which have their axial line *AZ* perpendicular to the dip plane. Two secondary electrodes, *M* and *N*, connected by insulated cables 2 and 3 through potentiometer *p*, are lowered on an oriented column of tubing—such as the drill pipe—until they come within the influence of the electrical field maintained about electrode *A*. (For a discussion of methods of orienting tubing in wells, see page 712.) The tubing is then turned until a minimum (approximately zero) potential is recorded on the potentiometer and the electrodes *M* and *N* will be on an equipotential surface and consequently in a plane at right angles to the dip of the beds. When electrodes *M* and *N* are rotated into the dip plane, the potential difference indicated will be a maximum.

An alternate and preferred method of determining the direction of the axis of equipotential surfaces about electrode *A* makes use of a magnetic teleclinometer, which employs an induction compass to measure its direction with respect to the terrestrial magnetic field. The Dipmeter instrument, employed by the Schlumberger Well Surveying Corporation, utilizes the magnetic teleclinometer which, with the electrodes, is housed in a long, metallic cylindrical case, designed to be lowered on an insulated three-conductor cable, into an uncased well filled with water or drilling fluid. Two of the insulated conductors are connected to the electrodes *M* and *N*, and the third to the grounded power electrode *A*. The dip components are measured with respect to two axes set in the apparatus, which is itself oriented in relation to vertical and magnetic north by means of the magnetic inclinometer. From the record thus secured, the azimuth with respect to magnetic north may be computed.

In order to eliminate the influence of local magnetic irregularities, the dip components are observed at a number of points near the level to be surveyed. The results are then plotted on polar coordinates and the average dip reading determined. Under favorable conditions, the azimuth of dip can be determined with an accuracy of plus or minus 10 deg. If the well is not vertical, suitable corrections must be applied to the observed readings.[18]

Electrical Logging through Casing.—The usual method of electrically logging a well is dependable only when the electrodes are run in an uncased well. In many thousands of wells completed before the electrical logging methods were developed and applied, no electrical logs are available or can be made because of the presence of casing. For such cases, the Strata-Graph has been developed and is offered for oil-field use by a service organization in certain regions in the United States. This device makes use of a traveling zinc electrode suspended on an insulated conductor cable, that may be lowered through a column of electrolyte (drilling fluid or salt water) filling the well opposite the interval to be surveyed. At the surface, the conductor suspending the electrode in the well is grounded in a solution of copper sulphate. An intricate electrical apparatus, balanced to offset conductor resistance, produces a fluctuating self-potential record that, it is claimed, is responsive to changes in the lithologic character of the formations penetrated by and cased off in the well. A flow of current, supposedly occurring from one formation to another through the casing, is transmitted through the electrolyte from the casing to the electrode. The recorded e.m.f. is logged with respect to a depth scale and a median voltage reference line. Portions of the record to the right of the median line represent sands; portions to the left, shales. Strata-Graph records of near-by wells seemingly permit of dependable correlations of the formations logged by their self-potential patterns. Oil sands, originally cased off in wells, have been located with this device, the casing gun-perforated in these intervals and production secured.

RADIOACTIVITY WELL LOGGING

A unique system of well logging involves observations of radioactive emanations from the strata exposed in the walls of wells. All rocks display some degree of radioactivity and this property is sufficiently characteristic to afford a means of distinguishing between shales and sands, limestones, salt, anhydrite and other materials frequently present in sedimentary formations. A continuous record of radioactivity, secured by traversing the well with an instrument sensitive to these emissions, is automatically correlated on a chart with a scale proportional to the depth of the well. Variations in the lateral amplitude of the radioactivity profile develop a pattern that is characteristic of the formations penetrated. These patterns, apparent in the radioactivity logs of different wells in the same locality, are often sufficiently similar to permit of accurate stratigraphic correlations. Radioactivity emanations are capable of passing through steel and cement and are influenced but little by fluids present in the well, or by temperature and pressure conditions. Radioactivity logging is therefore particularly useful in logging formations sealed off behind casing in previously drilled wells for which no electrical logs are available.

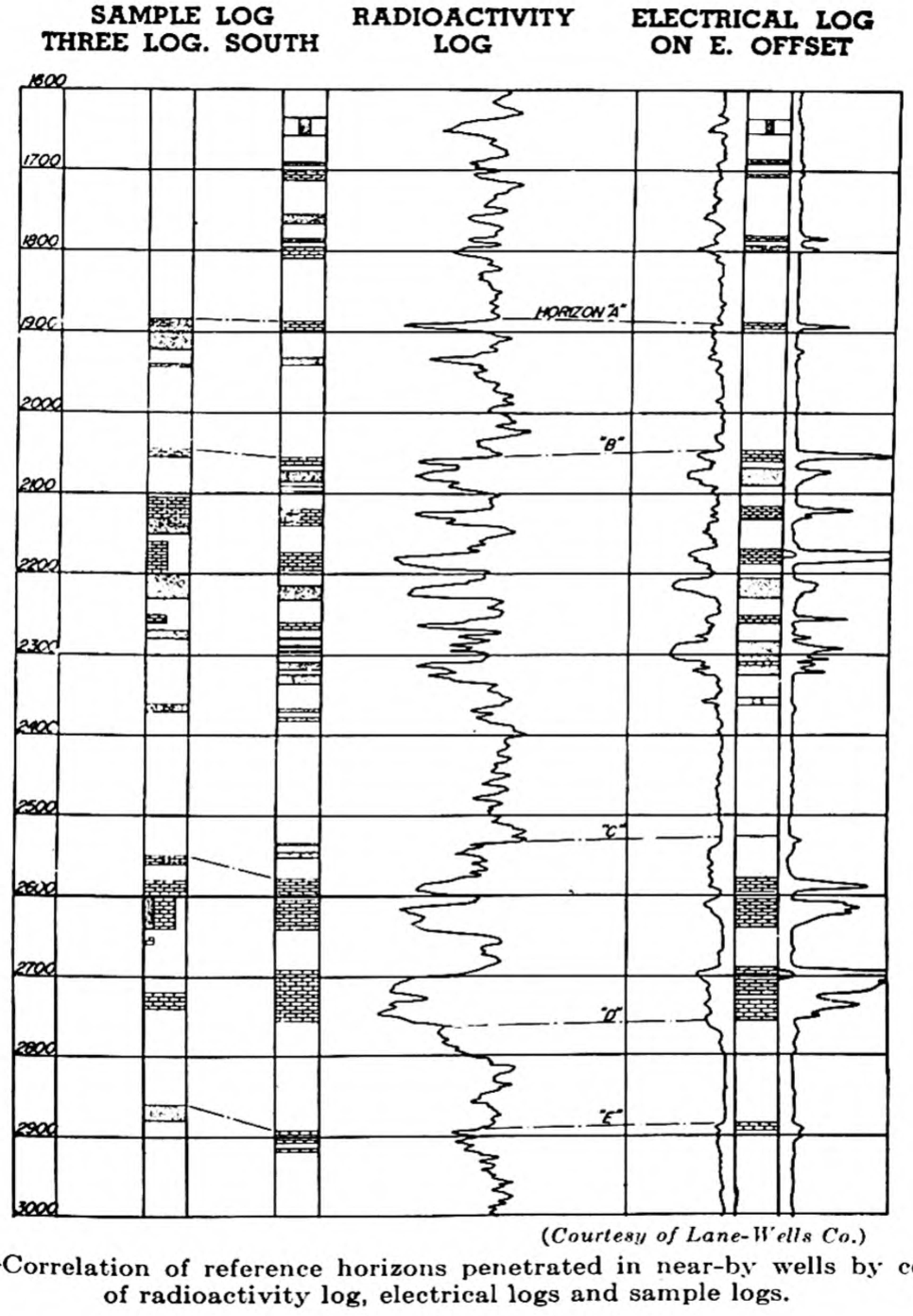
Theoretical Basis for Radioactivity Logging.—Certain substances appear to be of unstable constitution, disintegrating spontaneously to form other substances of lower molecular weight, of different physical and chemical properties. In this transformation, energy is liberated in a form which is characterized by electronic discharges to which the term "radioactivity" is applied. Particles of matter, expelled at high velocity from radioactive substances, give rise to what are called "beta rays," and when these rays strike other substances, they produce electromagnetic "gamma rays." Gamma rays are like light rays but are of much shorter wave length. They display the penetrating effects of X rays, characteristic of radium emanations, and are capable of being detected with sensitive instruments through several inches of steel casing or cement on the wall of a well.[26]

Many naturally occurring mineral substances exhibit radioactivity in varying degree. Radium, a highly radioactive substance, is widely distributed in primary rocks, but in very minute amounts. Uranium, actinium and thorium are also radioactive elements that disintegrate to form other radioactive substances widely distributed in nature. Measurable quantities of the disintegration products of these radioactive elements are found in rocks of all ages and all kinds. Early disintegration of a primary radioactive mineral is rapid, but the products of disintegration apparently do not reach energy equilibrium, even in geologic time. As granite and other igneous rocks are transformed into metamorphic and sedimentary formations, the radioactive elements persist and, by some process of nature not fully understood, are apparently concentrated in some types of strata in preference to others. Shales and clays ordinarily exhibit greater radioactivity than sands and sandstones, particularly certain dark-colored marine organic shales, rich in potassium compounds. In some regions, the geologically older shales appear to be more radioactive than the younger shales. Pure quartz sandstones and limestones display very low radioactivity. Coal is also weakly radioactive, as are salt, anhydrite and other salines.*

Radioactivity Logging Equipment.—Methods have been devised for determining in the laboratory the relative degrees of radioactivity displayed by core samples taken during the process of drilling wells. However, a less expensive and more complete log of radioactivity, exhibited by formations penetrated during the course of drilling, may be obtained by traversing the well with an instrument sensitive to radioactive gamma rays. This is essentially an ionization chamber, suspended on a coaxial cable which carries electrical impulses to the surface where their magnitude is automatically recorded. The logging instrument is contained within a steel cylinder about 9¾ ft. long and 3⅝ in. in outside diameter, closed at each end against the well fluid. It is filled with a gas of high molecular weight (such as Freon, a compound derived from

* Uren, L. C., Radioactivity and Geochemical Well Logging, *Petroleum Engr.*, January, 1943, pp. 50–58.

methane, containing chlorine, fluorine and carbon) and is fitted with insulated electrodes connecting externally with a source of d-c electricity. The upper part of the instrument contains batteries that furnish current to the ionization chamber, and an amplifier of special design. Current flows through the circuit only when the ionization chamber is brought within the influence of gamma-ray emissions from radioactive substances. A measurable current, proportional to the intensity of the radioactive



(Courtesy of Lane-Wells Co.)

FIG. 275.—Correlation of reference horizons penetrated in near-by wells by comparison of radioactivity log, electrical logs and sample logs.

emanations, then flows through the gas between the electrodes of the ionization chamber. This is of the order of one ten-trillionth of an ampere and must be greatly amplified by the instrument before it may be transmitted through the suspending coaxial cable to the surface. In surface apparatus, the electrical impulses are further amplified before they can be recorded on a scale that clearly reflects variations in the radioactivity of the formations logged. Changes in the magnitude of the amplifica-

tion may be made from time to time to magnify small variations in intensity of the radioactivity record which may result when unusual thicknesses of steel casing or cement are interposed between the logging instrument and the formation.

The equipment sent to the well includes two motor trucks: an instrument or recording truck and a truck carrying a winch on which the cable is wound. At the well head, the cable passes over an accurately calibrated depth-measuring reel, which is connected through a Selsyn transmission system with a depth-recording device in the instrument truck. A pen on the recording instrument fluctuates with the intensity of the current received from the logging instrument in the well, and draws a log on a moving chart that is synchronized in its movement with the depth-recording instrument. In making a log, the instrument is lowered to the bottom of the well and then hoisted toward the surface at a uniform rate averaging about 1,500 ft. per min. However, the speed of travel of the instrument is varied according to the character of the formations logged and the amount of detail desired. Graphic radioactivity logs drawn by the recording instrument may be made on a scale of either 100, 50 or 20 ft. per in. Figure 275 reproduces a typical radioactivity log and demonstrates correlation with electrical and sample logs.

Interpretation of Radioactivity Logs.—Radioactivity logs are continuous profiles displaying variation in the gamma-ray intensity of radioactive emanations relative to depth. The intensity varies with the lithologic character and content of radioactive material in the formations. In interpreting radioactivity logs, it should be kept in mind that the recorded variations in lateral position of the radioactivity profile are only relative and lack quantitative significance. There are problems incidental to drift of the entire record laterally, resulting from variations in temperature and other conditions affecting the instrument, and problems incidental to the degree of amplification employed, that preclude any quantitative interpretation of the record—at least in the present state of development of the art. Within a distance of perhaps 50 ft. from the surface of the earth, cosmic rays from the atmosphere produce about the same effect upon the ionization chamber of the logging instrument as do gamma rays from the adjacent rock masses. Hence, radioactivity logs are meaningless until this depth has been reached.

If the radioactivity profile swings toward the right side of the record, it indicates that, at this depth on the log scale, the clay or shale content of the formation increased. If it swings to the left, the formation contains less clay or shale than the interval below. Intervals on the profile, characterized by comparatively low radioactivity values, are probably made up largely of sand, sandstone or limestone strata. Intervals of comparatively high radioactivity value are probably composed largely of shale or clay strata. The profile is thus made up of peaks of high radioactivity, representing shale or clay bodies, and valleys of low radioactivity representing sands, sandstones or limestones. Radioactivity logs closely resemble in appearance the self-potential profile of an electrical log. Unlike the electrical log, however, the radioactivity log affords no direct basis for estimating porosity or permeability of the formations logged, or the character of the contained fluids. Indirectly, it is of course possible to infer that an increase in the clay or shale content of a formational interval means smaller percentage porosity and lower permeability, and vice versa.

Alternations of shale and sand bodies, and variations in their thicknesses in a certain formational interval, often produce a characteristic pattern on the radioactivity profile that identifies the interval, so that where the beds are continuous over an area, dependable correlations may be made between different wells in that area. It has been demonstrated that in some regions it is possible to correlate certain formations in wells many miles apart by comparison of these characteristic patterns developed in the radioactivity profiles. Radioactivity logs will often

indicate minor shale "breaks" only 1 or 2 ft. in thickness in a body of sandy material, thus affording a dependable basis for locating useful reference horizons that may not be made apparent in other systems of logging. Unconformities and fault planes, presenting marked changes in lithology within a short distance, are often distinctly marked on the radioactivity log by nearly horizontal deflections of the profile. Location of the bottom of a cement plug or position of the lower end of a column of casing is usually indicated by an abrupt shift of the profile to the left. The top of a cement plug is usually marked by a gradual drift to the right. Reference points of this character can be located within 1 or 2 ft.

Though steel casing and cement screen the radioactivity emanations from the formation to a certain extent, satisfactory radioactivity logs may be made through several strings of casing or several inches of cement that do not differ materially from logs made in the same well before the casing and cement were installed. The log made in open hole shows somewhat more detail and slightly better differentiation between shales and sands. Fluid in the hole surrounding the logging instrument or in the formation—whether water, mud fluid, gas or oil—has little effect upon the result.[32]

Utility of Radioactivity Logs.—Ability of the radioactivity log to reflect the lithologic character of the formations through casing suggests its most useful application: that of identifying prospective oil sands through casings in wells that have previously been drilled and cased to produce from a lower horizon. In many cases, such wells were drilled before electrical logs were known, and no accurate records of other kinds were made to indicate the positions of oil sands passed up or unrecognized during the drilling period. In many such instances, prospective oil sands have been located by radioactivity logging through casing in wells cased to produce from greater depths and, on perforating the casing, the sand intervals have been found to be commercially productive. In this service, the radioactivity log has no recognized competitor.

One of the principal fields of usefulness of radioactivity logs will probably be found in making engineering studies of partly depleted oil fields for prospective secondary recovery operations. In the older fields, it is seldom that the earlier records provide sufficient information concerning the detailed stratigraphy of the producing formation to make intelligent provision for control of secondary recovery operations. Often the producing formations are cased off behind a perforated liner or screen pipe. Without disturbing the well casing and screens, the radioactivity log may be successful in securing a detailed stratigraphic record of the alternating strata of sands or limestones and shales that make up the producing interval in the well. In addition, the radioactivity log finds a field of usefulness in checking stratigraphic depths carelessly or inaccurately logged in earlier drilling.

Dependable information relative to character and thickness of strata cased off in old wells may thus be made available and new light brought to bear in the solution of hitherto confused correlations and stratigraphic relationships.

Neutron Logging.—Radiation phenomena afford other methods of approach to the problem of logging formations exposed in wells than that described in the foregoing paragraphs, which involves direct observation of the magnitude of emissions of spontaneously developed gamma rays. The neutron, one of the fundamental components of matter, is liberated by atomic dissociation. Bombardment of the formation in the wall of a well with a stream of neutrons generated by an instrument containing

radioactive material, such as a mixture of radium and beryllium, results in emission of gamma rays from the solid portion of the rock mass. The magnitude of these emissions is determined with the aid of an ionization chamber such as that described in the foregoing section. It is believed that the neutron method of logging may be helpful in providing a means of indicating the porosity and fluid content of formations behind a column of casing. Owing to a peculiar action of hydrogen nuclei in influencing the movement of neutrons, the method may be successful in detecting the presence of hydrocarbons.[31,36]

GEOCHEMICAL WELL LOGGING

In geochemical well logging, formation samples systematically gathered in the course of drilling are subjected to delicate methods of chemical analysis that quantitatively indicate the presence of minute quantities of hydrocarbons, hydrogen and other components. The amounts of these constituents, plotted graphically against a depth scale, often develop characteristic patterns that are found to be indicative of the presence of oil and gas accumulations in underlying or near-by formations. Geochemical logs thus develop data which, when intelligently interpreted, afford a means of predicting the probable success or failure of a drilling operation before it is completed. Providing a direct means of forecasting the presence or absence of hydrocarbons in formations ahead of the drill, they may be of great value in petroleum exploration and oil-field development.

Theoretical Basis for Geochemical Well Logging.—The modern concept of an oil or gas accumulation concedes that the overlying sediments are not capable of completely sealing the fluids in the reservoir rock: that within geologic time subsequent to accumulation of the deposit, slow migration of hydrocarbons through the overlying sediments has resulted, in many cases, in formations all the way to the surface displaying minute quantities of hydrocarbons and their decomposition products. Even samples of soil, gathered about the surface of the earth above the oil deposit, often contain minute amounts of hydrocarbon that can be detected by delicate methods of chemical analysis. When systematically sampled and quantitatively analyzed, such surface accumulations often disclose a "halo" of hydrocarbons in the surface soils surrounding the oil deposit, with lesser amounts in the area immediately above. Apparently diastrophic forces, or little understood geochemical effects incidental to upward migration of fluids, result in formation of more indurated and less permeable formations immediately above the oil deposit. Ideas concerning the subsurface paths of escaping hydrocarbons through the formations overlying oil and gas deposits are largely a matter of opinion based on theoretical concepts, and some geologists familiar with the

vagaries of sedimentary stratigraphy question whether there can be any general pattern that would apply to all or even a majority of structures. Yet, study of the results of geochemical logging do support the theory—in many cases at least—that distribution of the hydrocarbons in the formations above and about oil fields follows some recognizable pattern.

Formation Sampling and Chemical Analysis.—Formation samples are gathered at intervals ranging from 10 to 180 ft. of well depth, depending upon the amount of detail desired. Usually one sample is taken for each joint of drill pipe added to the drill column, or about every 30 ft. The samples sent to the laboratory for analysis may be core samples or a representative collection of drill cutting gathered from the mud ditch or vibrating screen and washed free of drilling fluid. A minimum of about 100 grams of material is necessary for a complete analysis, which requires about 5 hr. of laboratory work. However, several analyses may be conducted simultaneously. Samples should be as fresh as possible and are preferably kept moist during shipment from the field to the laboratory. If a properly equipped laboratory is not within convenient shipping distance, a trailer laboratory containing the necessary analytical equipment may be stationed at the well.[38]

A complete chemical analysis of a formation sample for geochemical logging purposes may include determination of the percentage by weight of (1) hydrogen; (2) total hydrocarbons and further classification of hydrocarbons under three headings, (2*a*) methane, (2*b*) gaseous hydrocarbons (methane through butane), and (2*c*) distillate hydrocarbons (pentane through decane). The amounts of these components are determined by highly sensitive methods and apparatus capable of detecting one part in a billion by weight. Additional components determined by analysis of the formation samples may be (3) carbonates (undifferentiated carbonates and bicarbonates); (4) sulphates; (5) halides (undifferentiated chlorides, bromides and iodides); and (6) acid-soluble sand.

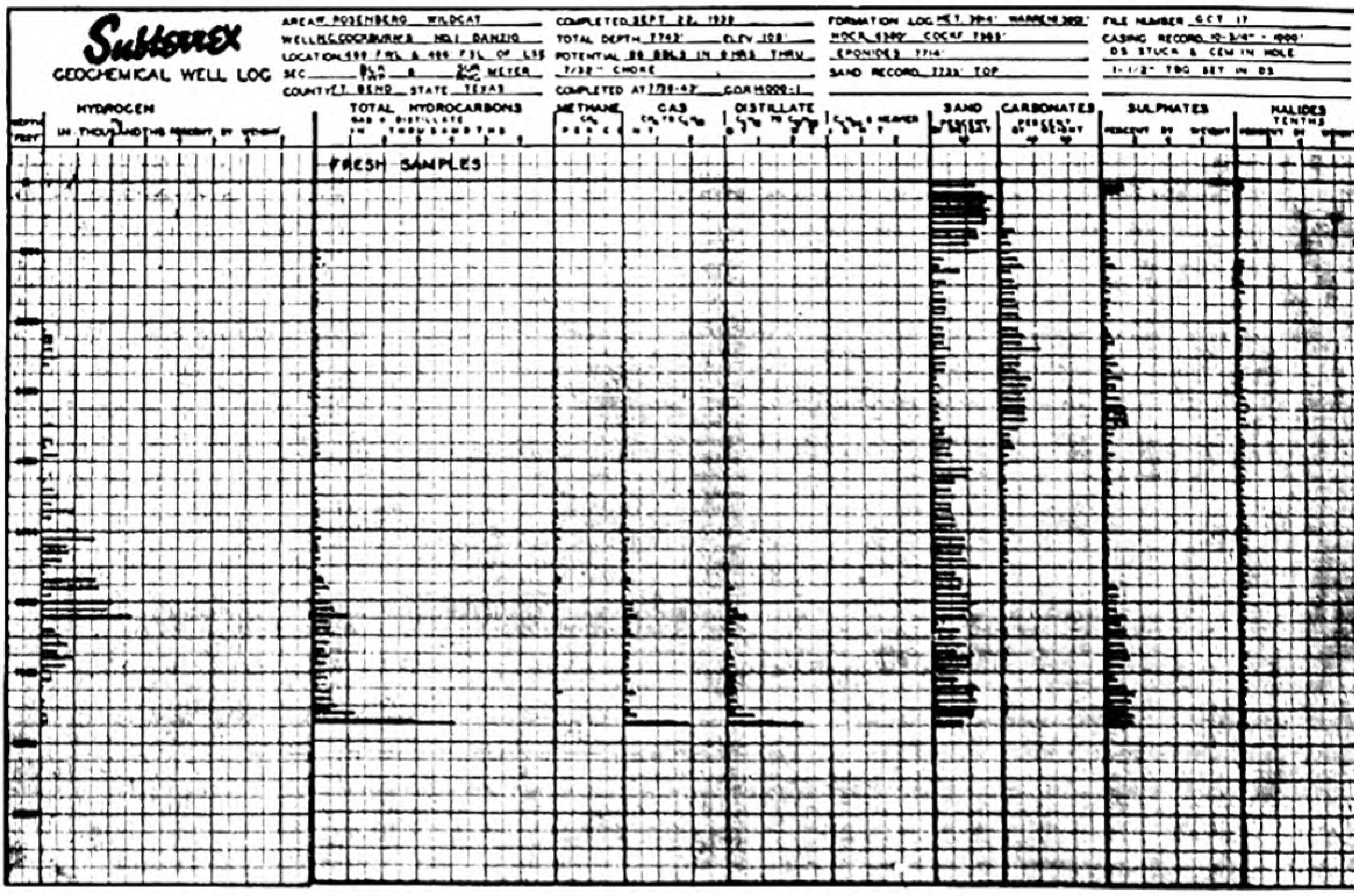
In the course of the analysis, some hydrogen is often evolved. Though its source has not been clearly determined, its presence is believed to be correlated in some indirect way with the presence of hydrocarbons in underlying sediments. The quantity of "gaseous hydrocarbon" shows the summation of amounts of hydrocarbon ordinarily present in natural gas. The amount of methane included in this is separately reported because of the possibility that it may be indigenous to the sediments in which it is found, hence not significant as an indicator of oil or gas in underlying formations. The distillate hydrocarbons are those normally included in natural gasoline. Other properties mentioned above, which may or may not be included in the analysis, are not considered of diagnostic value in indicating the presence of hydrocarbons, but are of value in lithologic studies and classification and correlation of the rocks comprising the strata penetrated and of their contained fluids.

The mass spectrometer may advantageously be employed in analysis of the hydrocarbon components of the formation samples. This is an electronic device by means of which gas analysis which previously required days of time in the laboratory can be completed in a matter of minutes. Purity of hydrocarbon gases can be determined within a fraction of 1 per cent. In this device, ionized gas molecules move at high velocity through a controlled magnetic field which sorts out the molecules according to their weights. It has been developed as a self-contained unit, the only outside connections required being for 110-volt a-c power and water for cooling the pumps.

Method of Graphically Displaying Geochemical Well Log Data.—Results of the chemical analyses of formation samples are plotted as separate profiles, side by side on a uniform vertical scale of depth, so that they can be directly compared (see Fig.

276). The logs are normally plotted to a scale of 1 in. to 500 ft., which permits of convenient over-all inspection and comparison of the several profiles. An enlarged scale of 1 in. to 100 ft. is used for more detailed studies. The logs are posted from time to time while drilling is in progress and as the data become available. Properly interpreted, they may thus serve as a guide in planning for deeper drilling.

Interpretation of Geochemical Logs.—The hydrocarbon logs often display characteristic depth patterns. The amount of total hydrocarbon may gradually increase with depth until, when the oil-producing formation is approached, a rapid increase is noted (see Fig. 276). The hydrogen log characteristically shows gradual increase with depth, until a maximum is reached some distance above the oil-bearing formation—perhaps many hundreds or even a thousand feet or more—and then abruptly diminishes. The magnitudes of the maximum values of total hydrocarbons and hydrogen,



(*Courtesy of Subterrex.*)

FIG. 276.—Method of graphically displaying results of geochemical well logging.

and the relative depths at which they characteristically appear, vary with the position of the well on structure, and are an expression of the paths of escape of hydrocarbon gases and vapors from the oil deposit.

If the productive formation contains oil, a substantial percentage of the hydrocarbon components will appear as "distillate hydrocarbons." If it contains only gas, the hydrocarbon constituents will be primarily methane and gaseous hydrocarbons. If the log shows rapid increase in hydrocarbon content, the prospects for finding commercial production in formations immediately below are considered good, especially if a characteristic hydrogen profile has been logged at shallower depth. Thus, it may be possible to predict the proximity of a producing formation with some certainty when the bottom of the well is some distance above—even several hundred feet in some cases. With such information, plans may be made in advance for setting casing, coring and formation testing. The geochemical log gives insurance against premature abandonment of wells and the operator may be encouraged to drill deeper than he had originally intended, with the prospect of finding production from a lower

source. The owner may be encouraged in making additional lease commitments, even before a test well is completed.

If the log shows erratic hydrocarbon and hydrogen values or no consistent trend, it is considered an adverse indication. Dry holes customarily display nothing but low values. Thus, the operator may be justified in abandoning operations at shallow depth and saving the cost of useless deeper drilling. If the total hydrocarbon profile shows high values, reaching a maximum shortly below a well-defined peak on the hydrogen profile, then diminishes abruptly as greater depth is attained, but commercial production is not found, it may be inferred that the well is somewhat "off structure" and that production may be found in the vicinity farther up-dip. Where a multizone situation exists, with several productive sands at different depths, the hydrogen and hydrocarbon profiles may show a separate "echo" for each, and superimposed values may lead to complex profiles difficult of interpretation.

Although there are differences of opinion concerning matters of interpretation and validity of theories upon which interpretations are based, it is nevertheless true that the anomalies recorded in the geochemical log have a certain degree of diagnostic value, not only in petroleum exploration, but also in field exploitation. Variations in the amount and kind of hydrocarbons, hydrogen and other significant components in formations overlying and surrounding petroleum deposits, as disclosed by geochemical logs, should be a matter of scientific interest and value to the geologist in interpreting the lithologic and stratigraphic conditions, and should be particularly useful in interpreting the results of wildcat drilling and in planning development in newly discovered producing fields where the limits of production have not yet been determined. The cost of geochemical well logging service is not excessive ($10 per sample) and the information that it provides may be worth many times the cost.

CONTINUOUS INSTRUMENTAL LOGGING OF ROTARY-DRILLED WELLS

A system of logging depth, thickness, character and fluid content of formations penetrated in rotary drilling, in which most of the necessary data are automatically recorded as the well is drilled, has been developed and is offered to the industry on a service basis by the Baroid Sales Division of the National Lead Co. and the Seismograph Service Corp. of Delaware. The methods employed depend upon tests that are continuously made to detect changes in the liquid phase of the drilling fluid and rate of penetration of the drill. The equipment employed is elaborate and intricate and is permanently mounted in a house-type trailer that is left at the well in the care of a skilled operator while drilling is in progress. The trailer is also equipped with instruments employed in testing the physical properties of drilling fluids and in core inspection and analysis. Except for electrical logging, the equipment provided is thus capable of giving the operator a complete logging and field laboratory service.

In the process of drilling, the bit disintegrates the formation in its path and fluids present in the pore spaces of the rock become a part of the liquid phase of the drilling fluid. Though the amounts of oil, gas or salt water thus added to the drilling fluid are small, they are sufficient to be clearly apparent in the delicate tests that are applied to the fluid

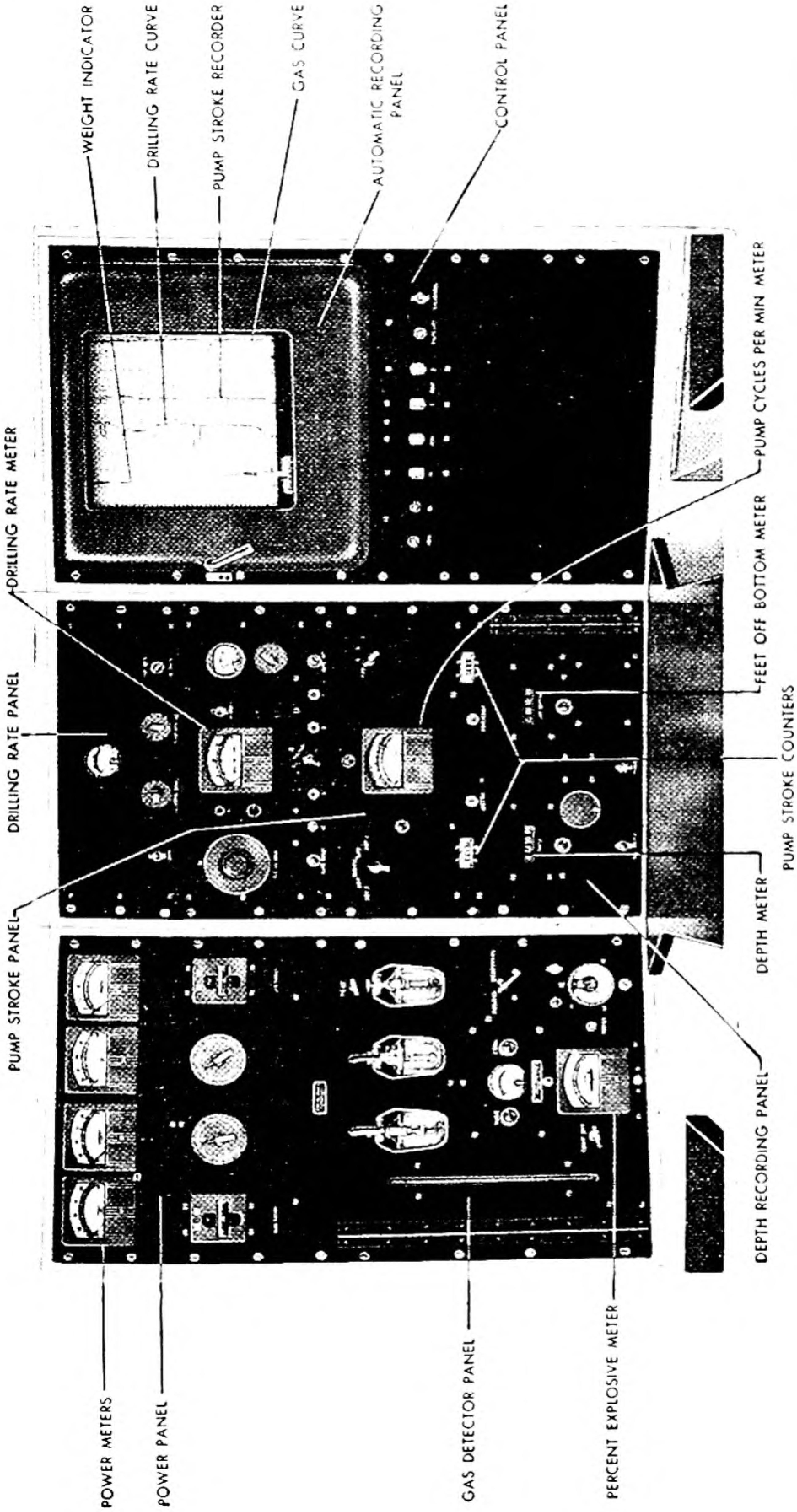
after it reaches the surface. In order to correlate the fluid thus detected by such tests with the stratum from which it came, it is necessary to take into account the time intervening between the drilling of the material and the delivery of it at the surface in the drilling fluid. A log of rate of penetration versus depth is also obtained and differences in the recorded rate of penetration may be used as an index of the lithologic properties of the strata penetrated. The depth to the top and bottom of each sand stratum is thus disclosed and sands are clearly differentiated from shales.*

The test equipment employed in this system of logging may be divided into two groups: (1) that used for detection of oil, gas and salt water in the drilling fluid returns and (2) that necessary in registering the depth of the well, the rate of penetration and rate of drilling-fluid circulation. The latter must be known to correlate surface observations with the depths to which they relate. The instruments used are electrically operated and power for operating them is obtained either from the source that drives the drilling rig, or from a 1½-kw. gasoline-driven generator carried as a part of the equipment of the trailer laboratory. Figure 277 presents a view of the instrument panel in the trailer and indicates the arrangement of the equipment that it carries.[49]

Depth determinations are made by two independent means: first, the drilling-rate record, which continuously and automatically is recorded against depth. By this means the tops and bottoms of sands and more permeable beds encountered in drilling are indicated. This record is supplemented by a second determination which depends upon a volumetric metering of the circulating fluid and the time necessary for formation samples to travel from the bottom of the well to the surface. A depth recorder in the trailer laboratory continuously indicates the depth of the well and the distance of the bit off bottom and drives a chart in synchronism with the rate of increase in depth. The sclerograph, or drilling-rate meter, operates in conjunction with the depth recorder, the rate of penetration being determined by measuring the volume of fluid displaced by the slush pump, as indicated by a pump-cycle counter. The number of pump cycles necessary to bring a sample from the bottom of the well to the surface is a factor that must be known in this system of logging, and is determined from time to time by actual test. The necessary time, of course, increases with the depth of the well, averaging about 6 min. per 1,000 ft. of depth. With the types of slush pumps used in rotary drilling, the volume of drilling fluid displaced per cycle is practically constant and the number of pump cycles necessary to bring fluid from the bottom of the well to the surface becomes a measure of its depth. A large meter shows at all times the rate at which the pump is operating and this is also indicated on the record chart in "fluid units."

Minute quantities of gas entrained in the drilling fluid delivered at the surface are identified by a gas detector. A motor-driven vacuum pump constantly draws air through a trap mounted on the drilling-fluid flow line, and thence through a flexible hose to the trailer laboratory where it passes through a filter, a humidifier, a flow meter, and thence to a "hot-wire" bridge-type gas detector. In the latter, two filaments, maintained at different temperatures, make it possible to distinguish between wet and dry gas. This instrument can detect as little as 0.01 cu. ft. of gas per hour

* Uren, L. C., Recent Developments in Formation Logging, *Petroleum Engr.*, February, 1943, pp. 63–70.

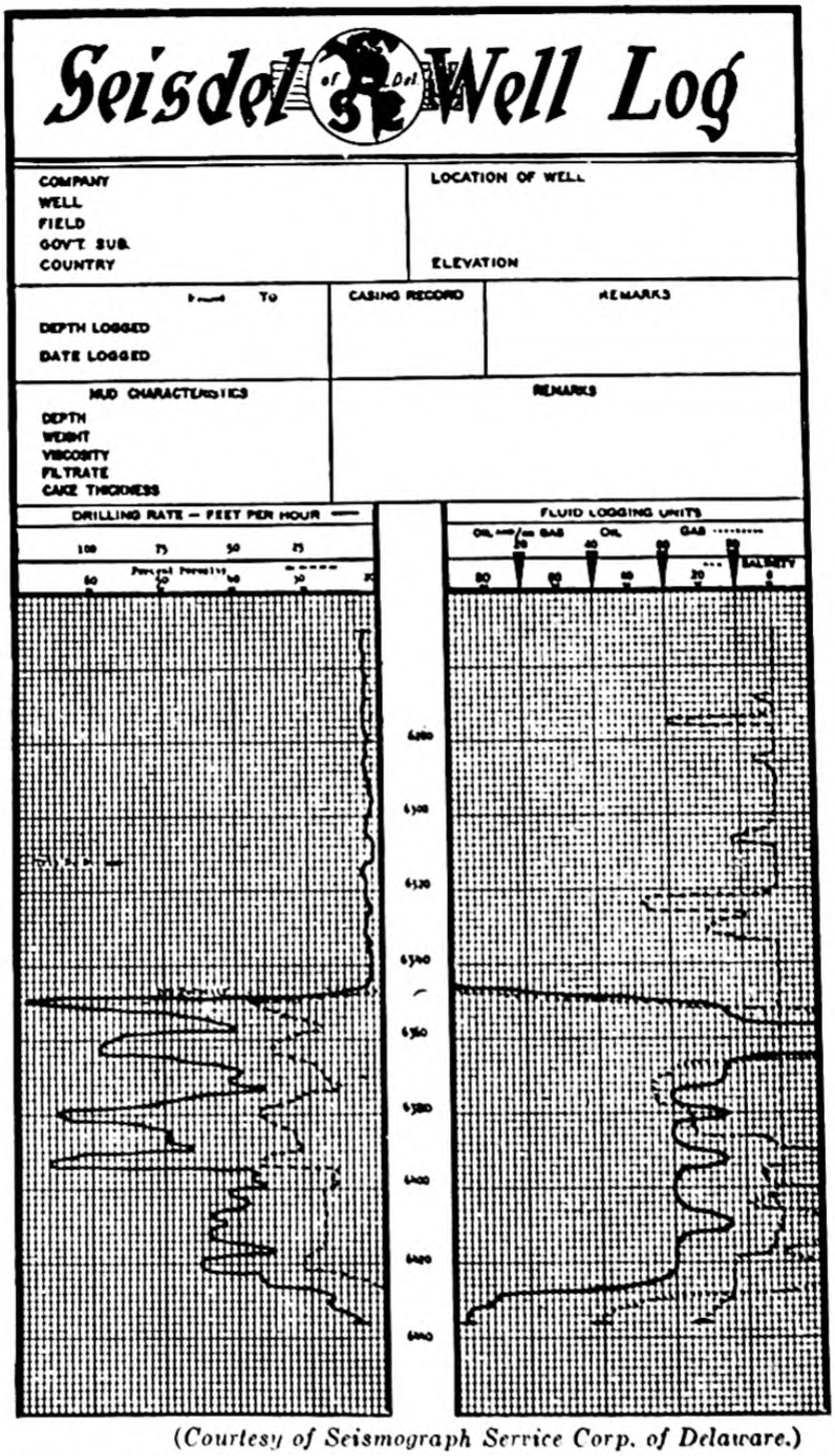


(*Courtesy of Baroid Sales Division, National Lead Co.*)

Fig. 277.—Instrument panel of trailer laboratory used in logging by observations on circulating fluid used in rotary drilling.

mixed with air drawn from the trap. The gas detector is connected with the recording apparatus, so that its signal appears on the recorder chart. Facilities are also provided to test core samples for gas with this apparatus.

Ultraviolet light is used as a means of identifying oil particles in the drilling fluid. A sample of the mud stream is placed in a dish, diluted with water, a viscosity and



(*Courtesy of Seismograph Service Corp. of Delaware.*)

FIG. 278.—Graphic method of reporting results of continuous instrumental observations on circulating fluid used in rotary drilling.

emulsion "breaker" is added and the dish and sample are placed in a specially designed viewing box. The latter is equipped with a source of ultraviolet light and an alternate source of visible light and magnifying eyepiece for inspection of the sample. Under ultraviolet light, crude oil fluoresces and, if present in the mud sample, appears in the form of bright specks on a dark background. By observing a fluorescent spot and then switching on the visible light, it is possible to distinguish between crude petro-

leum and other oils or greases that may accidentally get into the mud, from the swivel, for example. Fluorescence due to presence of petroleum in the mud is marked only when the oil is first produced, and gradually disappears if the mud containing the oil is circulated repeatedly through the well. To supply dependable drilling-fluid samples for testing, a continuous sampler is placed in the mud ditch. This is in the form of a revolving wheel which takes a small sample with each revolution and deposits it in a sample container. By this means, an average mud sample for any depth interval is obtained. With the equipment described, it is possible to detect oil in drilling fluid when the concentration is only 10 parts per 1,000,000.

Salt water added to the drilling fluid as a result of disintegration of rock strata by the drill is detected by an electrical device. Electrodes, placed in the flow line and in the pump suction, record the electrical resistance of the outgoing and ingoing drilling fluid. Superimposing the input resistance record for a portion of the ingoing mud stream, over the recorded resistance of the same portion of fluid as it issues from the well, discloses any change that may occur as a result of passage through the drilling zone. If the fluid is more conductive after passage through the well, salt water has been added. Making due allowance for time lag, the recording apparatus automatically indicates the difference in resistivity between the ingoing and outgoing fluid. For successful logging of salt-water "shows," the liquid phase of the drilling fluid must be comparatively fresh.

Figure 278 presents a typical log developed from records taken with the apparatus described in the foregoing paragraphs. An interpretive graphic log drawn to the same vertical scale may be superimposed on the center of the record. The value of a system of logging in which all of these useful indicators will be made known promptly, as drilling proceeds, will be apparent. Such a record, supplemented by an electrical log and occasional cores, gives a fairly complete subsurface picture and accurate and timely information of the location of all oil and gas sands encountered in the course of drilling.

TEMPERATURE SURVEYS IN OIL WELLS

As explained in a previous section (see page 16), the geothermal gradient in any given locality is fairly constant and is only locally altered by conditions that are frequently of interest to those concerned with the problems of oil-field development. The normal gradient is about 1°F. for each 60 ft. of depth, in some localities much greater, but this is appreciably altered in the vicinity of formational intervals in wells where gas is expanding or liquids are flowing from the well into the formation or vice versa, or where chemical change is occurring—as for example, in the setting and hardening of cement behind casings. Knowledge of these local variations in the normal temperature gradient is of assistance in locating the positions of water, oil and gas sands or gas-oil contacts in producing reservoirs; in determining variations in permeability of component members of an oil- or gas-producing zone; locating casing leaks or the source of water entering a well; or locating the top of a column of cement in the annular space behind a string of casing. Temperature surveys have the advantage over some other methods of gathering subsurface information, in that they can be applied inside of casing.

Types of Instruments Used in Temperature Surveys.—Thermometers used in making temperature surveys in wells are of three types: (1) the maximum mercury thermometer which, on being lowered into a well and withdrawn, indicates the maximum temperature reached; (2) the self-contained, continuously recording type that is designed to be lowered through the well on a wire line and indicates the temperature at all depths on a record contained within the instrument, available only after the instrument has been withdrawn to the surface; and (3) the continuously recording type, in which only an instrument responsive to thermal change is lowered into the well, while the temperature is simultaneously indicated or recorded on an instrument at the surface.

Maximum mercury thermometers have been widely used in studies of geothermal gradients in oil fields but are capable of securing temperature measurements only at intervals through the well. Inasmuch as the instrument has to be lowered into and withdrawn from the well for each observation, the method is tedious and the record fragmentary. For these reasons, it is considered less suitable than the continuously recording types of thermometers.

Self-contained recording thermometers for use in wells are designed to register on a chart contained within the instrument, a continuous record of temperature to which it is subjected. A stylus, which charts the record, is responsive to a metallic coil or the pressure of an imprisoned gas or vapor that expands and contracts with change in temperature. The chart is rotated under the stylus by a mechanism that can be correlated with the movement of the instrument through the well. Contained in a cylindrical casing, the device is lowered into the well on a piano wire or light wire cable. Such instruments have the advantage that they and their winding mechanism are light and require little power to operate, and they can be run against high well pressures.

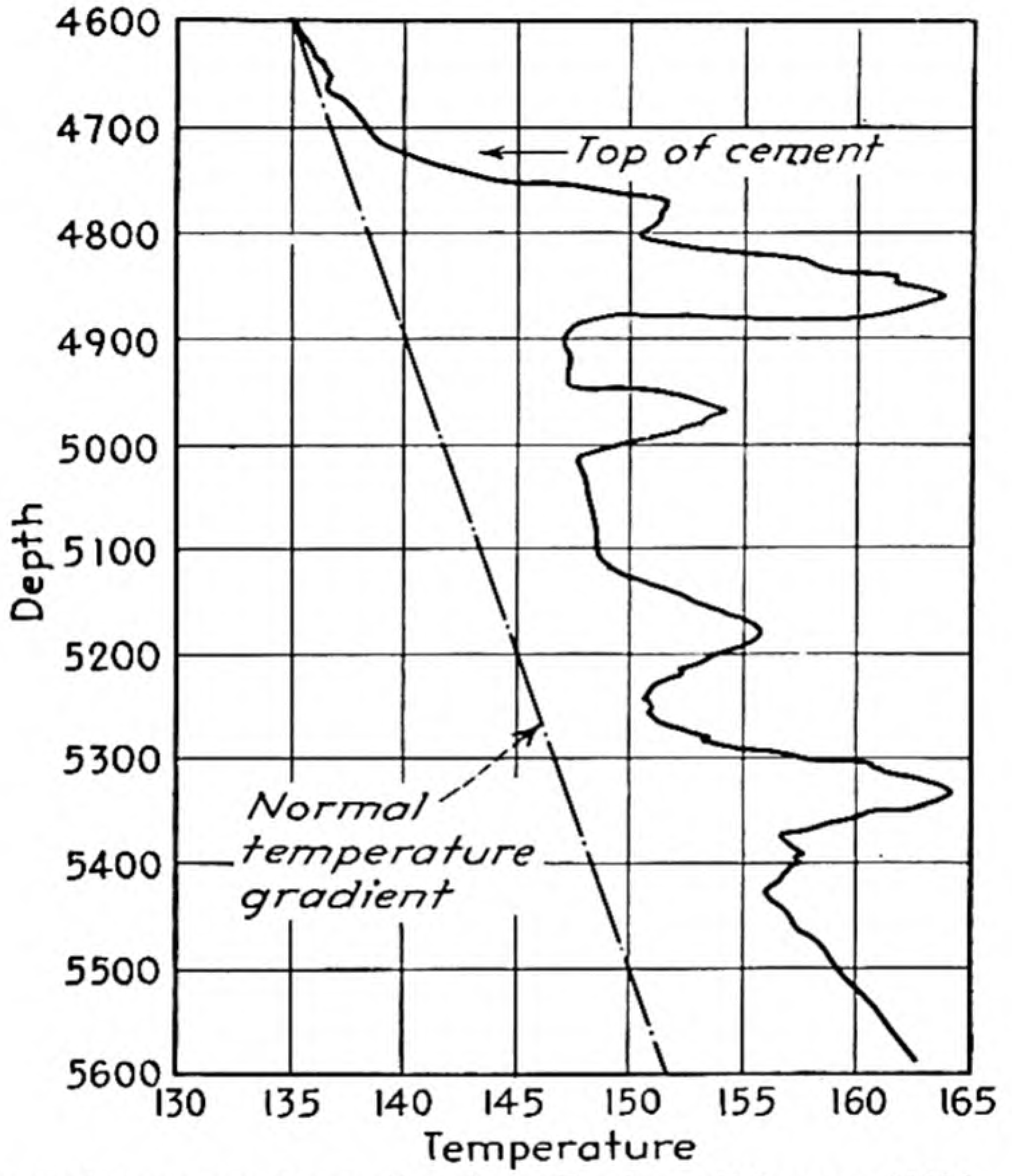
A surface-recording thermometer is of the electrical resistance type and must be lowered on an insulated conductor cable. The latter is expensive and, being heavy, requires a power-driven winch to reel it. Indications of temperature can be continuously observed on an electrical instrument at the surface, or a continuous record can be obtained that can be correlated on a chart against depth measurements on the cable.

A thermometer suitable for practical use in petroleum engineering operations should be capable of securing a continuous record, preferably one that can be observed as it is being recorded. It should be sufficiently sensitive to permit of recording to within 1°F. or less and have a low thermal lag so that it will quickly respond to changes in temperature. Furthermore, it should be ruggedly constructed to withstand successfully the conditions to which it is subjected in oil-well service. The electrical-resistance type of thermometer, with continuous surface recording of temperature, appears to meet these requirements best.

The Schlumberger Well Surveying Corporation has developed a resistance type of thermometer designed to be run on the same insulated conductor cable used in connection with resistivity surveys. Indeed, the two are often combined. Two of the insulated conductors are connected to a spool of resistance wire having a high temperature coefficient, that is lowered into the well. The wire of which the resistance spool is constructed is insulated and the resistance that it offers to flow of current varies with the temperature. At the surface, the two conductors are connected to a source of direct current through a Wheatstone bridge or potentiometer which measures the resistance in the circuit. By using three conductors connected through a bridge at the surface, the effect of the well temperature on the resistance of the cable can be compensated. The instrument can be run in holes as small as 2½ in. in diameter. The temperature of the instrument lowered into the well is recorded on a surface

instrument in the form of a continuous graph plotted as abscissas against depth ordinates. Wells are surveyed with this apparatus at a rate of about 1,000 ft. per hr.[46]

Applications of Temperature Surveys.—One of the most useful purposes served by this type of temperature survey is the location of oil- and gas-bearing "pays" in limestone formations. Because of the cooling effect of expanding gas, it is feasible to distinguish between gas-yielding and oil-yielding strata. Oil-yielding reservoir rocks also show a cool anomaly on the temperature log because of expansion of gas released from solution in the oil, but the cooling effect is generally less marked than in cases where the gas is free in the formation. Where both are present, it is usually possible to distinguish between them by a pronounced change in temperature.



(From an article by the author in Petroleum Engineer, February, 1943.)

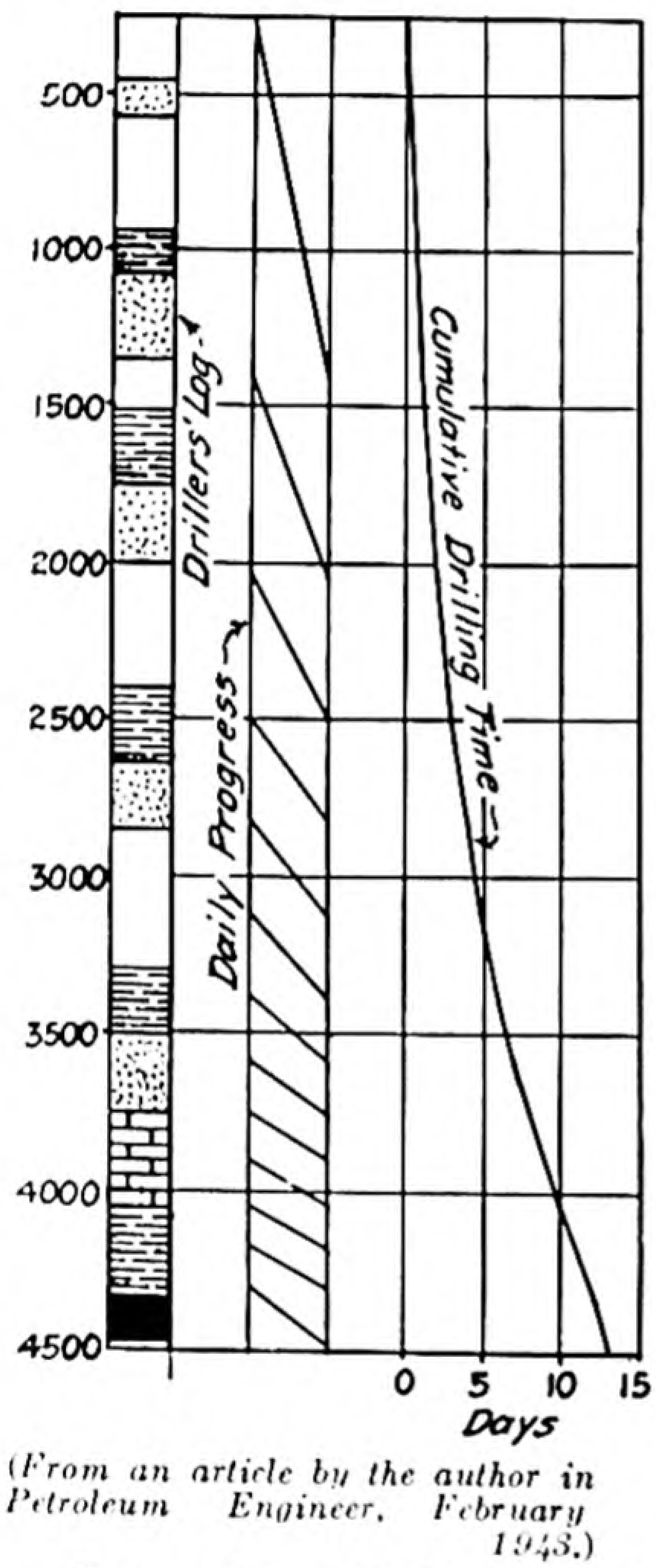
Fig. 279.—Temperature log, showing method of locating top of cement behind casing.

Reflecting the normal temperature gradient, the graph customarily shows approximately constant increase in temperature with depth, but locally, where influenced by the cooling effect of expanding gas, the temperature graph displays an abrupt departure from the normal trend. In some limestone fields, where a gas reservoir closely overlies the oil-bearing interval, it is important to set a column of casing to seal off the gas, just below the gas zone, without excluding any of the oil-producing zone. A temperature survey clearly shows the base of the gas zone so that casing may be set properly.[45]

In cementing casing in wells, it is helpful to know, after the job is completed, the height to which the cement has risen in the annular space outside the pipe. This is often uncertain when determined by volume computations, because of variation in diameter of the well, channeling of the cement, and tendency of the permeable formations to absorb some of the cement. The chemical changes involved in the setting and hardening of cement are exothermic and the heat developed is apparent

on the temperature survey for many days after the cement is in place and has taken its initial set, even though the heat must penetrate the intervening casing (see Fig. 279).

Temperature surveys are at times helpful in correlating formations from well to well, it being frequently possible to observe some common temperature anomaly that is peculiar to a certain stratum or group of strata in the temperature logs of near-by wells. In a well drilled by the rotary method, the temperature of the circulating fluid differs materially from that of the formation with which it is in contact, being lower at the bottom and higher at the top of the column of fluid in the well. When circulation is stopped, heat from the formations exposed in the walls of the well will tend to bring about temperature equilibrium with the formational temperature. Fluid in the upper part of the well will become cooler and that toward the bottom, warmer. However, the rapidity of heat exchange will depend upon the nature of the rock strata traversed by the well. For example, sands containing water have a high thermal conductivity and capacity and will release their heat to the well fluid more rapidly than shales. Oil sands, being poor conductors of heat, will release their heat less rapidly than water sands. A depth-temperature graph, recorded shortly after circulation has stopped, may thus distinguish to some extent between different strata according to their thermal conductivities, and similar records obtained in near-by wells will at times suggest correlations.[43]



(From an article by the author in Petroleum Engineer, February 1943.)

FIG. 280.—Methods of graphically displaying drilling time.

DRILLING-TIME OR RATE-OF-PENETRATION LOGS

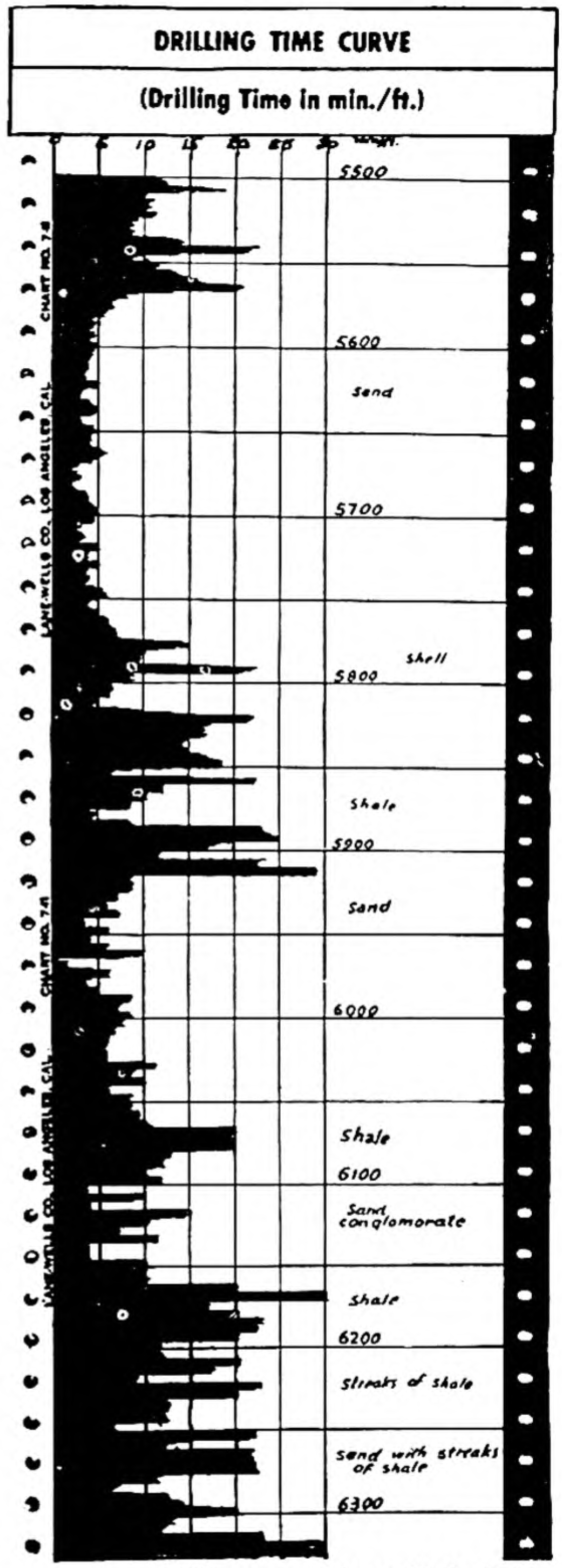
For many years, drilling-time records indicating the rate of penetration in drilling have been a matter of interest for a variety of purposes. Early records were, in many cases, a mere assemblage of figures showing the rate of progress in a stated depth interval. Often such records are prepared in graphic form, correlated with a graphic stratigraphic log. Thus, in Fig. 280, the graph at the right of the stratigraphic log indicates the progress made during each day of drilling, the slope of the inclined lines being a function of the rate of penetration. In gathering data for detailed rate-of-penetration records, the kelly is marked at 1-ft. intervals and the driller notes the time when each foot mark reaches the level of the top of the table bushings. Time is deducted for intervals when, for any reason, the bit is off bottom.

Drilling-time Recording Instruments.—Manually recorded drilling-time records require close attention on the part of the driller and, to free him of this responsibility, several automatic and semiautomatic drilling-time recording instruments have been

developed. A popular semiautomatic drilling-time recording instrument for use with rotary equipment is enclosed in a metal case and is mounted on a pedestal near the driller's position in the rig. Through a window in the front of the instrument case appears a chart which is moved vertically through a uniform interval whenever the driller presses a trigger projecting from the under side of the case. This he does each time one of a series of reference marks at 1-ft. intervals along the kelly reaches the level of the driving bushing of the rotary table. Each time the trigger is pressed, a recording stylus, actuated by clockwork, moves quickly to the left margin of the chart and begins drawing a horizontal line across the chart. This line progresses to the right at a certain constant rate per minute of time, and the length of the line drawn between two successive applications of the trigger thus becomes a measure of the rate of penetration. Figure 281 illustrates the type of record secured with this instrument.

A short line indicates a rapid rate of drilling; a long line, a slow rate of progress. The instrument is not connected in any way with the drilling mechanism and it places a minimum of responsibility on the driller, short of fully automatic recording. A graphic, easily interpreted record is produced on the chart of the instrument as drilling proceeds. No computations or translation of records on the drafting board is necessary. The driving mechanism may be adjusted for varying rates of movement of the recording stylus or pen and of the interval between horizontal lines representing the depth scale.

A fully automatic type of drilling-time recorder utilizes a simple fluid-pressure system connecting a reservoir mounted on the swivel of the rotary rig, through a flexible tube, with a recording pressure gauge below the derrick floor. A recording pen, responsive to the downward movement of the swivel on the upper end of the drill column, draws a continuous graph on a revolving circular chart. With this device, the record obtained at the well does not directly indicate the rate of penetration or the drilling speed, but requires interpretation. This is done with the aid of a transparent circular template which is superimposed over the record chart. Curved lines on the template, matched against the slope of the graph, indicate the rate of penetration at any time. Rates of



(*Courtesy of Lane-Wells Co.*)

FIG. 281.—Rate-of-penetration log produced by drilling-time recording instrument.

penetration must then be plotted in profile form with respect to a depth scale. This fully automatic drilling-time recording instrument provides a continuous record of all that is done with the drilling equipment during each hour of the day and thus provides the administrative officials with a basis for checking the activity and efficiency of the drilling crews.

Still another method of determining the rate of advance in drilling is that employed in the fluid-control system of continuous logging of drilling fluid described in an earlier section (see page 651). Here, by a knowledge of the volumetric capacity of the well per foot of depth and a determination of the time necessary for fluid to travel from the bottom of the well to the surface, the depth of the well at a given time can be determined. Successive determinations of this character indicate the rate of progress. In this system of logging, a companion instrument is used to indicate the depth of the well at any time. This is actuated by a pair of Selsyn motors, the primary motor being driven by mechanism that is responsive to the downward movement of the traveling block. An electrical instrument in the same circuit indicates the momentary rate of penetration of the bit and a recording pen draws a continuous drilling-rate profile on a strip chart moving under the pen at a uniform time rate.

Factors Responsible for Variation in Rate of Penetration in Rotary Drilling.—The rate of progress in drilling depends upon several factors. The lithologic character of the formation in which the drill is operating is a factor of primary importance, particularly its hardness—a property depending upon its mineral content, degree of cementation and character of the cementing material, porosity, permeability, etc. Other important factors are the design of the bit, its mechanical condition and extent of wear, and the downward pressure maintained upon it by the drill column. The rate of progress in drilling also depends, particularly in soft formations, upon the character and rate of circulation of the drilling fluid and the velocity with which it is ejected from the apertures in the bit. Another significant factor is the rate of rotation of the drill. Perhaps most important of all is the skill of the driller who, by manipulation of the draw-works brake, controls the rate of feeding of the drill as it penetrates the formation.

Utilization of Rate-of-penetration Data.—With so many factors influencing the rate of penetration of the drill, one would expect that it might be difficult to draw from a record of it any valid conclusions concerning changes in the character of the formation. Yet, it appears that most of these factors either tend to remain reasonably constant in their influence, or they are of so much less importance than the character of the formation that they do not prevent the rate-of-penetration data from being used as an index of formation resistance. The record is essentially one of comparative rather than absolute values. Certain it is that in many cases surprisingly accurate logs, showing depths to top and bottom of reference strata and character of material comprising different formation intervals, are secured by skilled interpretation of such records. Erratic control of bit pressure in manual regulation of the feeding mechanism may lead to conditions in which the rate of penetration fluctuates widely, but a process of averaging or integrating rates over longer time intervals will usually produce a significant result. Best results are secured where bit pressure is automatically regulated.[59]

A rate-of-penetration log often compares closely with the self-potential profile of the electrical log through the same interval. This is reasonable inasmuch as the rate of penetration doubtless bears some direct relation to the porosity and permeability of the formations drilled. Indeed, it is believed that in some areas the drilling-time log might be a better index of the lithology of the strata penetrated by the drill than the electrical log. It has the advantage over the electrical log that it is assembled while the well is drilling, whereas the electrical log is usually made after

the drilling of an interval is completed. In any case, the drilling-time record will be of material help in interpreting the electrical log.

Often drilling-time records will be of value in indicating likely reservoir rocks in formations penetrated by the drill. Thus, they have been of assistance in locating the more permeable and porous intervals in limestone reservoir rocks in central Kansas. Excellent correlations of formations between near-by wells are frequently possible by comparison of drilling-time records. Such records are also of value in any study of bit performance or of the comparative advantages of different bit pressures, rotational speeds, pump pressure and other conditions of drilling control. Studies of this character are helpful in increasing drilling efficiency. Drilling-time records are also of assistance in determining where cores may advantageously be taken before the opportunity to do so has passed, and they will be helpful in interpreting the results of coring when only partial recovery of the core is obtained. Firm strata in which to land casing may be chosen on the basis of the rate-of-penetration record.[54]

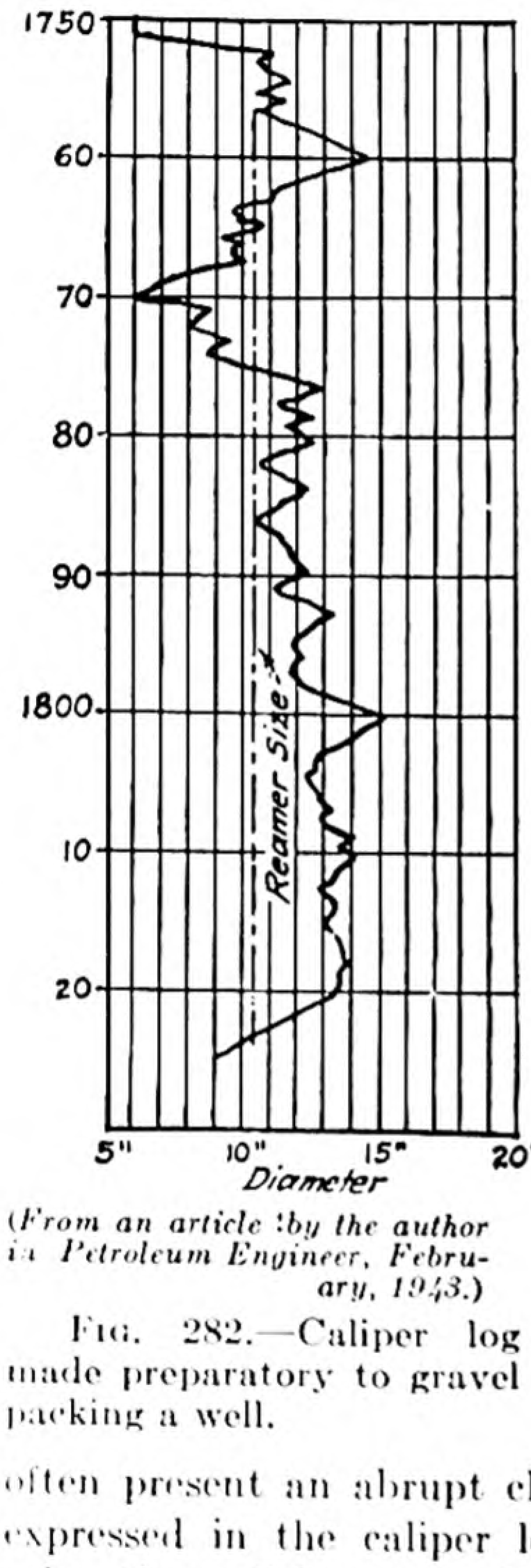
CALIPER LOGGING

Though the size of bit and drilling conditions may be maintained constant throughout a depth interval, the diameter of the well will vary with the character of the formations penetrated. Soft, unconsolidated and semiconsolidated formations tend to cave or are jetted or eroded away by the circulating drilling fluid, leaving the diameter of the well considerably larger than that of the bit with which it is drilled. In hard well-indurated formations, the diameter of the well is but little larger than that of the bit. Cavities of considerable size are sometimes formed by erosional influences, by influx of sand into the well with flowing gas or oil, or by use of explosives or by acid treatment of limestones. A record of variation in bore of the well throughout an interval will thus yield information from which changes in the lithologic character of the strata penetrated may be inferred. Knowledge of the diameter of the well at different depths is also helpful in planning various subsurface operations, as in cementing casing, gravel packing or selecting and installing packers.

The well caliper is a device designed to be lowered into the well on a wire line, which measures the diameter of the hole at all depths and records it automatically in the form of a depth profile. The caliper instrument has four collapsible arms mounted 90 deg. apart on a steel frame, each arm independently of the others being extended outwardly against the wall of the well under the tension of a spring. The instrument is lowered on the suspending wire line to the bottom of the interval to be logged, with the arms in collapsed position. The arms are then released and the instrument slowly raised through the well. The supporting line passes over a measuring reel which indicates the depth of the instrument at all times. As it moves upward, the ends of the arms maintain continual contact with the walls of the well. By electrical means, the position of the arms with respect to the axis of the instrument is at all times indicated on an instrument at the surface, which records directly the diameter of the well in log form against a depth scale. Figure 282 is illustrative of the type of record secured.

Applications of Caliper Logs.—Caliper logs are particularly helpful in planning well-cementing operations. In plugging wells with cement, it is necessary to know the volume of the well through a certain depth interval; or, in cementing casing, the

volume of the annular space between the casing and the wall of the well through the interval to be cemented must be determined. This is not ordinarily known with any degree of accuracy because of local variations in the bore of the well. A caliper log affords information from which the amount of cement necessary can be computed with fair accuracy, and thus we may be assured that the space we desire to fill will be completely filled and waste of cement due to overestimates can virtually be eliminated. Much the same problem is presented in gravel-packing well cavities through productive formations. The caliper log affords data with the aid of which the amount of gravel necessary to fill the cavity can be computed accurately. In acid treatment of producing formations, it is important to know the comparative permeabilities of different component beds of the formation to which the acid has access. The strata that have yielded most to the disintegrating influences of drilling and production appear on the caliper log as the intervals of largest diameter, and are likely to be composed of the more permeable beds which will absorb acid most readily. Packers may be set to exclude these strata in order to confine the acid to the beds of lesser permeability. In setting packers to close the annular space between casing or tubing and the wall of the well, it is important to set the packer against firm rock in a hole of a diameter in which the packer has been designed to function. Expensive packers, manufactured to precision dimensions, often fail to serve their intended function because they are set in a hole larger than that for which they have been designed. Methods of side-wall coring involve use of tools that are designed for successful operation only when the wall of the well is within a few inches of the coring tool. A caliper log will disclose intervals in which such devices may be used to advantage.



(*From an article by the author in Petroleum Engineer, February, 1943.*)

FIG. 282.—Caliper log made preparatory to gravel packing a well.

Caliper logs usually present a succession of peaks and valleys, forming a profile that is characteristic of the sequence of formations penetrated by the well. Where formations are regular and continuous, caliper logs of different wells in the same locality often display very similar profiles, so that it is possible to correlate formations from well to well with fair certainty. Marker beds and reference horizons in the section often present an abrupt change in lithologic character of the beds that is clearly expressed in the caliper log. In drilling through formations containing soluble salts, the well bore may be materially increased by solution in the drilling fluid of the material exposed in the wall of the well. A timely caliper log will disclose this condition and suggest changes in character of the drilling fluid to minimize the difficulty.[62]

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CHAPTER XVI

WELL RECORDS AND SURVEYS; INSPECTION OF FORMATION SAMPLES

In the preceding chapter, the several methods of logging wells to determine the lithologic character and nature of the fluid content of the formations penetrated in drilling were explained and the methods of recording well log data were described. The present chapter will be concerned with other methods of gathering subsurface information that is often incorporated in the well logs, and with methods of surveying wells to determine their declination and course and types of maps and records that may be derived from well logs and surveys.

FIELD INSPECTION AND ANALYSIS OF FORMATION SAMPLES

In gathering data for the stratigraphic record, it is desirable that classification of the materials comprising the various strata penetrated by the well be made on the basis of suitable formation samples by one capable of properly identifying them lithologically and mineralogically. In the drilling of wildcat wells or wherever the securing of an accurate stratigraphic record for correlation purposes is important, the larger oil companies frequently take special precautions in securing representative samples of each stratum penetrated and employ geologists or engineers skilled in this class of work to classify the materials accurately. Such work may go far beyond the mere identification of the kind of rock composing the sample and may include identification of the fluids present within its pore spaces, determination of its porosity and permeability, the size distribution of its component grains, as well as microscopic inspection to determine its fossil and mineral content. Although not widely practiced during the earlier period of oil-field development in the American fields, work of this nature has recently found application and promises to become increasingly important in future. Many of the problems of the oil producer that now seem difficult of solution will be easier of analysis when more complete and dependable stratigraphic information is made available.

Types of Formation Samples and Their Comparative Value for Quantitative Inspection Purposes.—We may classify formation samples primarily in accordance with the system of drilling employed in securing them. Thus, in cable or churn drilling, we may seek (1) bailer samples, (2) bit samples, (3) chip samples, or (4) cable-tool cores. In drilling by rotary methods, we may secure formation samples (5) by wash-

ing fragments from drilling fluid circulated to the surface, (6) by coring with conventional types of rotary core barrels operated on drill pipe, (7) by wire-line retrievable core barrels, (8) by the hydraulically actuated side-wall coring tool, (9) by coring with diamond drilling equipment, or (10) by the pressure-type core barrel. Other types of formation samples that may be secured in the drilling of wells either by churn or rotary methods include (11) side-wall samples secured with retrievable punch-type coring cylinders propelled by explosives, and (12) formation fragments drawn into the barrels of guns in gun perforators by resurgence of the well fluid following discharge of the bullets.*

Conditions attending the routine of drilling and economic considerations will determine which of these methods of securing formation samples will be employed. Each has its own inherent advantages and disadvantages. Cable drilling often produces coarse fragments of the formation in which the drill has been working, retrieved from bottom either by bailers of conventional type or suction type (such as the Cavins bailer). Frequently, on withdrawing the drilling tools to the surface, bit samples as large as one's fist will be found embedded in clay adhering to the water courses of the bit. Cable-tool bailer and bit samples are of somewhat uncertain value inasmuch as they may be contaminated by cavings from the wall of the well some distance above bottom and only the harder portions of the formation persist in the form of fragments large enough for analytical purposes. "Chip" samples are obtained by employing a bit dressed to a sharp edge so that it cuts coarse flakes from the formation instead of the ordinary cable-tool bit which develops more of a crushing action. Cable-tool core barrels are designed to apply the impact action of the cable method of drilling to cut a core from the formation exposed in the bottom of the well (see page 189). Such a core is likely to be broken into thin "biscuits," seldom more that a few inches long, and the less well-consolidated portions of the formation are often disintegrated in the process of coring. Yet, in hard formations, where the cable tools are most used, fairly dependable and little disturbed formation samples may be secured by this means.

With rotary equipment, the returns circulated to the surface with the drilling fluid are usually too far disintegrated to be of service for other than qualitative inspection, and recourse is usually had to the use of a double-barrel type of coring tool where formation samples are desired for quantitative tests (see page 357). Proper choice of a suitable type of cutting head for the core barrel, to adapt it to the formation in which the core is to be taken, will make it possible to secure fairly satisfactory and dependable samples under a wide variety of conditions. In soft, unconsolidated formations, pressure applied by the cutting element may result in partial disintegration of the less well-indurated portions of the core so that the percentage recovery of the cored interval is not so large as might be desired. Also, the core is caked with clay from the drilling fluid, but this can be scraped off and the core may be several inches in diameter so that the interior, near the center, is uncontaminated by drilling fluid. Wire-line retrievable core barrels are used primarily because they permit of taking cores of the formation in the path of the drill without interrupting progress by withdrawing the drill pipe from the well (see page 360). Though obtained at lower cost, they are of smaller diameter and therefore less well adapted for quantitative inspection.

At times it is desired to secure a core sample from the wall of a well in formation previously penetrated by the drill. For this purpose, the Baker side-wall coring tool, actuated by pressure of the drilling fluid, is available (see page 362). Cores taken with this device are thoroughly dependable, though somewhat small for complete analytical inspection. Of the several types of formation samples secured by rotary

* Uren, L. C., Inspection and Analysis of Formation Samples: Selection and Preparation of Samples for Laboratory Inspection, *Petroleum Engr.*, April, 1943, pp. 72–76.

methods, none is more dependable for laboratory study than the diamond drill core. This may be several inches in diameter and is cut by a diamond-set annular bit which operates with a minimum of pressure, contamination and compaction of the material cored (see page 349). The diamond drill secures an unusually high percentage of recovery in all types of rocks. No other type of core barrel functions so well in hard formations. The pressure core barrel has, as yet, scarcely been developed to the point where it may be used for routine formation sampling (see page 361). Gun-perforating operations often bring to the surface in the gun chambers small fragments of the formation opposite the perforations formed in the casing. However, the samples are too small to be of service in quantitative studies. Side-wall cores secured with the aid of the Schlumberger gun-type sample taker (see page 363) are thoroughly dependable but are not so large as is desirable for complete analytical inspection.

Alteration of Formation Samples in the Process of Coring.—Excessive bit pressure, sometimes employed in coring, may have a destructive effect upon the material cored, perhaps crushing or shearing the cementing material holding the grains together and compacting the rock structure so that its porosity and permeability are reduced below their actual values as they exist in the formation. Excessive bit pressure or inadequate supply of drilling fluid may result in sufficient heat being generated to fuse certain minerals in the core, thus seriously altering the lithological properties. Contamination of the core with clay caked about it and driven into its outer pore spaces by the high hydrostatic pressure existing in the bottom of the well often seriously alters the fluid content of cores taken by rotary drilling methods. Granular rocks exercise a selective capillary effect on the well fluid. The superior surface tension of water causes it partly to displace oil from the outer portion of the core. Compaction, resulting from pressure of the cutting tool in coring soft rocks, may squeeze out some of the native rock fluids.

"Bleeding" of the core as it is withdrawn to the surface, occasions loss of part of its contained oil and gas. This results from release of gas from solution in the oil and subsequent expansion as pressure is reduced. The jetting effect of drilling fluid against the bottom of the well may result in washing some of the oil from the pores of rock in the path of the cutting tool, so that the core contains less oil and more water than does the formation in place. By cutting large-diameter cores and using only the center portions of them for analytical purposes, we can perhaps avoid some of these difficulties, but at best, the worthiness and representative character of the fluid content of a core sample must be viewed with some uncertainty. However, the oil found in the core on analysis may be regarded as a minimum value, the amount originally present in the formation having been something in excess of this.

Field Inspection of Core Samples

When the core barrel is withdrawn to the surface, the core should be removed from it as soon as possible and carefully inspected by a technologist capable of interpreting his observations in terms of fluid content and lithologic properties. As removed from the core barrel, the core will normally be found broken into segments, some of which may be as much as 1 ft. or more in length, but often only a few inches. After the clay sheath surrounding the core is removed by scraping and washing, the segments are arranged in a suitable half-round metal or wooden tray, care being taken to place all parts of the core in their proper relationships. The depth to top and bottom of the interval cored in the well is indicated at each end of the core tray by suitable markers, and spacing blocks of suitable length are inserted at intervals between segments of the core where it appears that portions have been lost or destroyed in the process of coring. Core recoveries may at times be but a small

percentage of the interval cored, as measured by advance of the drill. Where two lost intervals occur in the same core, it may be difficult to determine the length of each missing section and the exact depths represented by different portions of the core between the known top and bottom of the interval cored.

Observations are made of the apparent fluid content of different component strata of the core. If gas is present, it may usually be detected by effervescence of small bubbles on the surface of the core. Water or oil, if present with the gas, will be partly expelled on the core surface by gas expansion, and the core will appear to bleed. It is easily possible to distinguish between oil and water thus appearing on the surface of the core. If but small amounts of oil are present, it may be necessary to make tests for its presence upon selected fragments with a suitable solvent, such as chloroform, ether or carbon tetrachloride. Very light, transparent and almost colorless oils that fail to produce the characteristic discoloration of the ordinary oil solvents may be identified by the acetone test.

A record is preserved of all observations made on first inspection of the core and careful measurements to the top and bottom of each stratum are made with respect to the top of the cored interval, so that an accurate log can be assembled. The position and character of each parting or break are noted, as well as any peculiarities that may be observed, such as cross-bedding, fault planes, joint planes, and solution cavities. Where the inclination of the strata with respect to the core axis can clearly be observed, the degree of dip should be measured and recorded. The type of rock comprising each stratum can usually be determined by casual inspection. Sands, sandstones, shales, conglomerates, clays, slates and limestones—the common sedimentary rock types—are sufficiently dissimilar to be identified even by the novice. Appearance of the core materials can best be described as to color while wet. With the aid of a pocket lens, the texture is noted: that is, whether the mineral grains are coarse, fine or medium in size, angular, subangular or well rounded. Such inspection may also disclose the nature of the cementing material. The more abundant mineral constituents may also be noted, as well as any fossils that may be observed.

Preparations are next made for selecting one or more samples representative of each component stratum. In so doing, care should be taken that the samples selected are, as nearly as possible, truly representative of the full thickness of the stratum from which they come. Samples of the core selected for laboratory inspection may be disks about 1 in. thick and broken, as nearly as possible, at right angles to the core axis. Cores of most sedimentary rocks will break readily along the bedding planes under light blows from a small hammer but, if the material is thoroughly cemented, it may be necessary to resort to the use of a heavier hammer and chisel to break out the desired portions. Splitting cores longitudinally exposes a section that is convenient for inspection across the bedding planes. A convenient device for this purpose, suitable for laboratory use, is manufactured by the E. J. Longyear Co., Minneapolis, Minn.

During transportation to a distant laboratory, the samples should be protected against loss of contained fluids by evaporation, seepage or bleeding. With this purpose in mind, they may be dipped in molten paraffin or wrapped in wax paper, tin or lead foil. Glass jars with metal screw tops, or ointment tins, may conveniently be used as containers for samples. The latter may be sealed around the lid joint with a strip of friction tape, or with molten paraffin. The container should be marked or a label attached in some permanent way to indicate the well number and the depth from which the sample came.

It is of course, an advantage if the laboratory can be near the well, for there is then less time involved in shipment and less opportunity for loss of fluid content of the core. Trailer laboratories, fully equipped for all ordinary core inspection tests,

may be stationed in the field where much coring and testing are to be done, thus avoiding the trouble and expense of preparing cores and time lost in shipment. Some of the larger oil companies maintain field laboratories at camp headquarters, within easy trucking distance of their drilling wells, but many operators utilize the services of testing organizations with laboratories situated perhaps many hundreds of miles from the field.

The whole purpose of core analysis is defeated unless the samples selected are truly representative of the formations from which they come. Some authorities question the value of accurate quantitative methods in the laboratory when the difficulties inherent in the problem of securing representative samples are considered. The core that is brought to the surface is, perhaps, 4 in. in diameter, or about $\frac{1}{12}$ sq. ft. in cross section. In any study of reservoir conditions, this must be considered representative of the strata throughout the surrounding drainage area influenced by the well. If this area is, say, 10 acres, the core is but 0.000,000,2 of the area that it is supposed to represent When one considers the variation in lithologic properties that may occur in a sedimentary formation within short distances, the possibility that the well has intersected the stratum at a point where average conditions obtain would appear to be remote indeed. It must be admitted that sedimentary formations ordinarily display great variation in texture, porosity and permeability and that abrupt changes in these properties occur within short distances, both vertically and laterally. In thin-bedded sediments, with rapid alternations of sandy and shaly strata, it may be extremely difficult to secure samples that have representative significance. The natural tendency to select samples that present optimum values in which we may be primarily interested should be resisted. Obviously a few "grab" samples taken at random are meaningless. The problem is complicated by the fact that the critical factors in which we are primarily interested are masked by mud accumulation and alteration of the exterior surface of the core in the process of cutting. Only one highly experienced in this type of work can be qualified to select representative samples of the core if but a few are to be sent to the laboratory. In view of the uncertainty inherent in the selection process, it would appear to be a better plan to test a larger number of samples and select them systematically. This does not mean that they should be taken at uniform intervals, for this method would obviously result in the inclusion of many meaningless samples. A sample from the center and from points near the top and bottom of each stratum would yield significant results in most cases, but any plan should be tempered by the good judgment of the engineer or geologist charged with the responsibility of selecting the samples.

Preparation of Samples for Laboratory Inspection.—On arrival in the laboratory, the sample is first carefully inspected by the analyst to determine its character and condition. If tests of fluid content are to be made, it is important to examine the container and any wrapping that may have been used, to determine the extent to which fluids have escaped from the sample during transit from the field to the laboratory. This may be difficult to estimate by casual inspection. Perhaps the best method of determining fluid loss is to weigh the sample in the field on a balance of suitable sensitivity, and then weigh it again in the laboratory after it has been removed from its container and wrappings.

Following arrival of formation samples in the laboratory, they are prepared for subsequent tests to determine fluid content, porosity, permeability and other lithologic properties that may be of interest. A portion of the sample to be subjected to test is selected and carefully cut or dressed to suitable form and proportions, which will be determined primarily by the requirements of the apparatus used in determining permeability. Another portion is selected for determination of fluid content.

Apparatus for determining permeability is often designed for use with cylindrical specimens, in preparing which a small drill press equipped with a diamond-set annular bit is used to cut a cylindrical core about 1 in. in diameter from the sample submitted. The cylinder may be cut from the sample in a direction at right angles to the bedding planes or along the bedding planes, as the objective of the test may require. Often two cylinders will be cut, so that permeability in each direction may be determined. The exact dimensions of the test specimens are determined by careful measurement. A test cylinder cut with the axis at right angles to the bedding planes may be tested for permeability and then a smaller cylinder may be cut from it for further testing, having the axis parallel with the bedding planes. Ends of the cylindrical specimens are carefully dressed with a small diamond-set disk saw, so that they present circular planes at right angles to the cylindrical axis. Careful brushing of the exposed surfaces with a stiff brush will remove from the rock pores dust formed in the process of cutting and dressing.

Preservation of Cores.—Cores from drilling wells are costly and often represent a considerable investment. They are not merely of temporary interest but will be of permanent value for reference purposes and may conceivably serve a variety of functions. Perhaps many years after they are taken, they will be a matter of interest in estimating recovery possibilities in controlling clean-out operations, placing packers and cement shutoffs, locating "shots" and other operations incidental to oil-well operation and repair. Since they are of permanent value, they should be carefully preserved by providing a place of storage where they may be systematically arranged for such inspection as they will occasionally receive. It will seldom be necessary to take precautions against evaporation losses from stored cores, since the results of the analytical inspection, made soon after the cores are taken, will presumably always be available as a record of the original fluid content. The trays or boxes containing stored cores should be labeled on the ends exposed in the rack, with the well number and depth to top and bottom. Where much coring is done and the cores from many wells must be stored, the bulk and weight of material to be cared for are large. Some operators transport all formation samples to a centralized point of storage; others erect at each well a small shed in which the cores from that well are permanently housed.

Extraction, Identification and Determination of Fluid Content of Core Samples.—The nature of the tests to be applied in determining the fluids present in a core sample, and their amount, will depend upon the amount of fluid (oil or water or both) that may be present, and whether merely a qualitative test or a quantitative measure of the amount present is required. In some cases, the sample will be well saturated and there will be no uncertainty concerning the presence of oil. In other cases, the sample may contain only small amounts of oil and delicate tests must be applied to determine its presence.

Qualitative identification of petroleum residues in such materials is comparatively simple. The solution-test method is the one generally employed, the common solvents for petroleum—such as chloroform, ether, carbon bisulphide or carbon tetrachloride—being discolored in a characteristic way by contact with petroleum, even though only small traces are present in the material under examination. Some oils are too light in color to yield a satisfactory test by these reagents. In this case the acetone test may be used to disclose their presence. This test consists in placing a little of the pulverized sample in a test tube or other glass receptacle with a little water. A few drops of acetone are added when, if oil is present, the water becomes milky in appearance. If considerable oil is present in the sample, a few minutes' agitation of a small portion of the material in a test tube or white porcelain dish may be sufficient to bring about the color change in the solvent; but, if only a small quan-

tity is present, a more delicate method must be employed. The following routine may be followed in extracting small quantities of petroleum from formation samples.

The sample is pulverized in a mortar and after drying for a time at normal atmospheric temperature, to permit of escape of moisture, 1 teaspoonful of the powdered material is placed in a clean 4-oz. bottle with 3 teaspoonfuls of pure chloroform or other solvent. The bottle is securely corked and then shaken for about 1 hr., taking care that the liquid does not touch the cork which may contain enough soluble material to discolor the solvent. A clean glass funnel holding a dry folded filter paper is placed in the neck of a second 4-oz. bottle and the contents of the first bottle poured on the filter paper, the filtrate accumulating in the second bottle being thus freed from sand or other visible solid particles. If the filtrate contains petroleum, it will be discolored to some shade of amber or yellowish brown, the intensity of color depending upon the quantity of oil present in the sample. The filtrate is next poured into an evaporating dish and allowed to evaporate in a warm place near an open window, taking care that no dirt, dust or other foreign substance collects in the dish. If the original sample contained petroleum, there will be left on the dish, after the solvent has evaporated, a yellowish or amber-colored stain, the darkness or intensity of which will depend upon the quantity of oil in the sample. In connection with this test, the analyst should remember that it is unsafe to evaporate chloroform, carbon tetrachloride or ether in other than a well-ventilated room. Neither is it safe to apply direct-heating methods in hastening evaporation, for the vapors coming into contact with a free flame or a heated metal surface will produce obnoxious gases such as chlorine, phosgene or other irritating or poisonous compounds.

Soxhlet's extraction apparatus lends itself well to determination of oil in formation samples, though the apparatus is somewhat more expensive and complex than that required in the simple test just described. Larger quantities of solvent are also required and the process of evaporation to obtain the oil-stained residue occupies a more extended period of time. Figure 283 illustrates one variation of the Soxhlet apparatus. The flask contains the solvent, which is heated by an electric hot plate. A tube penetrating the ground-glass stopper of the flask communicates with a larger glass tube which supports a porous alundum thimble in which the material to be treated is placed.* A siphon tube serves periodically to drain the solvent back into the flask, the lower part of the tube being closed. A vertical reflex condenser communicates through a ground-glass stopper supported in the upper end of the tube with the interior thereof. In operation, vapor from the heated solvent passes up through the vapor tube and thence into the water-cooled condenser. Here the vapor is condensed, dropping back through the lower end of the condenser on the sample under treatment in the porous thimble. The condensed solvent dissolves the oil in the sample and slowly seeps with the dissolved oil through the pores of the thimble, accumulating in the lower part of the containing glass tube until it reaches the overflow point of the siphon tube, when all of the accumulated liquid is siphoned back into the flask. The process continues, pure distilled and condensed solvent falling continually on the sample until it is completely leached, the solvent containing the solute being periodically siphoned into the lower flask, which thus gradually accumulates all of the oil originally present in the sample. When the extraction is complete, the solvent may be evaporated in a procelain evaporating dish, or distilled off, leaving the oil as residue.

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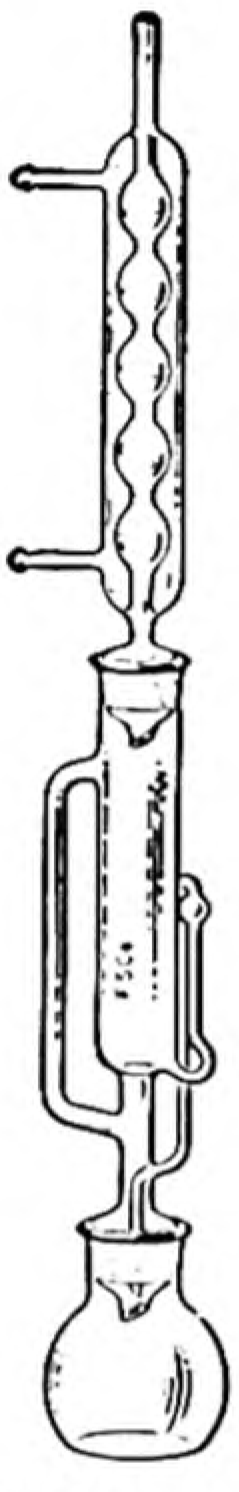
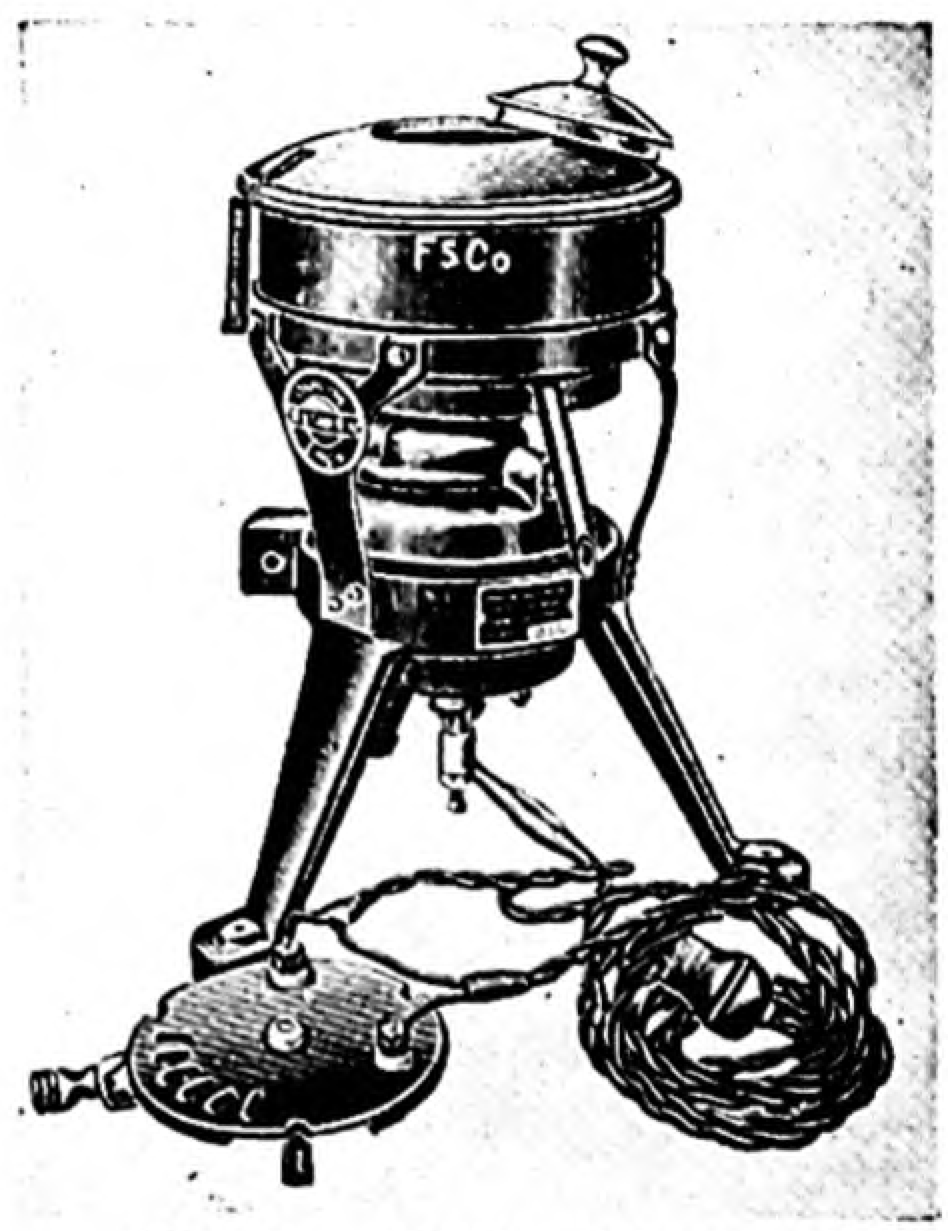
* For the extraction of oil from formation samples the Author prefers a filter-paper thimble manufactured by the Whatman Paper Company to the alundum thimble. These paper thimbles are inexpensive and a new one is used for each test.

Another laboratory device that is useful in extraction of oil from unconsolidated sands and small fragments of sandstone is the Dulin Rotarex illustrated in Fig. 284. This machine comprises a small metal bowl, mounted on a vertical, motor-driven spindle which may be revolved at high speed. The sand or sandstone fragments, from which oil or other bituminous matter is to be extracted, are placed in the bowl with a filter-paper pad placed between the cover of the bowl and the sand. While the bowl is rapidly rotating, an oil solvent, such as petroleum ether, carbon bisulphide or carbon tetrachloride, is poured into the bowl from which it flows through a hole in the spindle near the bottom of the bowl, thence up through the sample and out through the filter pad into the outer stationary housing from which it flows through a spout into a receiving vessel. A few minutes' treatment of a sample in this machine



(Courtesy of Fischer Scientific Co.)

FIG. 283.—Soxhlet extraction apparatus.



(Courtesy of Fisher Scientific Co.)

FIG. 284.—Dulin Rotarex, useful in extracting oil from formation samples.

will serve to remove all traces of oil from the sample. Owing to the high centrifugal force developed, the sample is left practically dry, but moderate heating after removal from the bowl of the Rotarex will be necessary to expel the solvent completely.

No one solvent is entirely satisfactory for all purposes. Oil and oil residues may be extracted with carbon tetrachloride, carbon bisulphide, benzol, benzene, cleaners' naphtha, pentane, xylene and similar solvents of hydrocarbon or related types, but for complete removal of water, acetone, butanol or ethylene dichloride is preferable. Two or more different solvents may be used in succession. Thus, the specimen may first be extracted with benzene to remove crude petroleum and petroleum residues, then with acetone to remove water, and finally with pentane to displace the acetone and facilitate rapid drying. Acetone is a convenient solvent, being miscible with both hydrocarbon oils and water and comparatively inexpensive. The solvent used must not alter the mineral structure of the specimen in any way and yet must have adequate solvent power for the fluids and soluble residues that may be

present. Some solvents, such as carbon disulphide, pentane and benzene, present serious fire and explosion hazards. Carbon tetrachloride has the great advantage of noninflammability.

After extraction, the specimen should be heated for a time at a temperature sufficient to evaporate all solvent from its pores. This drying of the specimen may be done in a thermostatically controlled oven maintained at a temperature below 210°F. It is important that temperatures much in excess of this be avoided; otherwise clays and other hydrated minerals that may be present may be altered by loss of their water of crystallization.

Determination of Fluid Content and Properties of Fluids Present in Core Samples.—It is often required to determine quantitatively the gross fluid content of a core sample. This may be done by weighing the specimen before and after extraction, as described in the foregoing section. The loss in weight after extraction is considered to be the weight of water and oil present in the pore spaces. Later, when the percentage of porosity has been determined, we may assume an average density for the contained fluids and compute the equivalent volume and the "percentage saturation." This is defined as the percentage of the pore space of the specimen occupied by liquids. Ordinary extraction, however, does not distinguish between water saturation and oil saturation.*

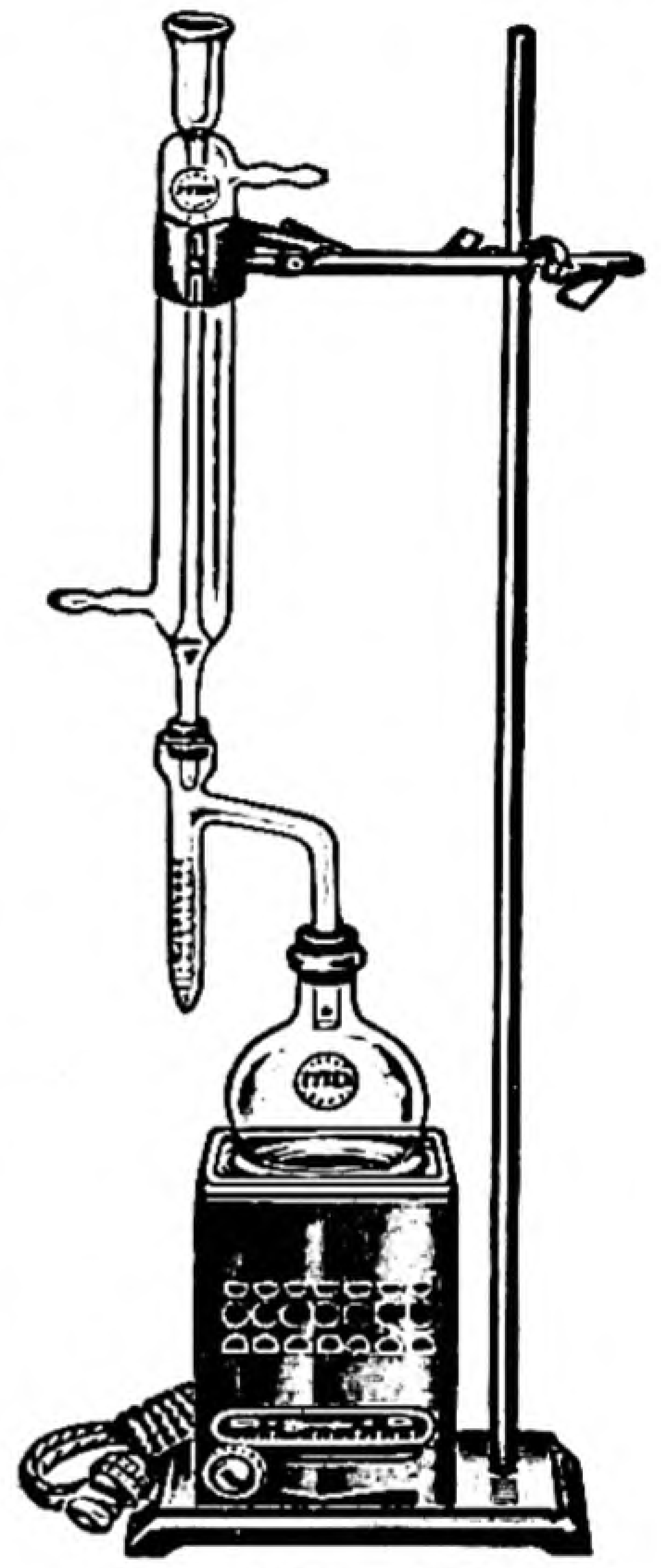


FIG. 285.—Distillation apparatus for determination of water in formation samples (A.S.T.M. test D-95).

Water saturation may be determined by placing the sample in a dessicated Soxhlet thimble, weighing and distilling in an apparatus such as that prescribed by the American Society for Testing Materials† for the determination of water in oil (see Fig. 285). Submerged in a suitable solvent,‡ the sample is heated in the distilling flask until the water is driven off and accumulated in the graduated receiving tube where its volume may be directly observed. The percentage of water saturation may then be computed in terms of the volume of the pore space as determined by quantitative methods.

After extraction of the water, the sample is transferred to a Soxhlet extractor and the residual oil removed. After complete extraction of contained fluids and drying of the sample, the over-all loss of weight is determined. The original weight of the sample minus the weight of the water removed, minus the final weight of the extracted and dried sample, is the weight of the oil content of the sample. If the density of the oil can then be estimated or determined, its volume can be computed and the percentage of oil saturation calculated.

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* UREN, L. C., Inspection and Analysis of Formation Samples: Determination of Fluid Content and Permeability of Core Samples by Quantitative Laboratory Tests, *Petroleum Engr.*, May, 1943, pp. 62–72.

† See A.S.T.M. test D-95, or pp. 562–564 of the companion volume "Oil Field Exploitation," McGraw-Hill Book Company, Inc., New York, 1940.

‡ A naphtha fraction having a boiling point ranging from about 90 to 210°C. is often used for this purpose; or a mixture of 80 per cent xylol with 20 per cent benzene will be found suitable.

A more rapid, though somewhat less accurate, method of determining oil and water saturation involves heating a separate sample of the core than that selected for porosity and permeability determination in a retort, condensing the oil and water vapors driven off, and directly measuring their volumes in a graduated burette. The metal retort is maintained at a temperature of 350°F. for about 40 min. while the water and all but the heaviest fractions of the oil are driven off. The retort temperature is then increased to about 1100°F. for at least 20 min. to drive out all residual hydrocarbons. The sample is carefully weighed before sealing it in the retort. Preferably about 150 grams is broken into pieces about 0.5 cm. in size and, after retorting, the weight is again determined. Loss of weight is the weight of fluids driven out of the specimen, and is compared with the weight of fluids collected in the graduated burette. The difference is considered to be gas or liquid lost or uncondensed in the process of retorting and an equivalent volume is added to the volume of the fluids condensed and measured. For accurate work, certain corrections must be applied to the observed loss of weight and measured volumes of oil and water condensed, to offset the loss of water of crystallization and dissociation of carbonate minerals, as a result of the high temperature applied. Some hydrocarbon residues may also be left in the sample in the form of coke, particularly if the oil is of low gravity.

Determination of Gravity of Oil in Core Samples.—It is necessary to know the approximate density of the oil in order to convert gravimetric to volumetric measurements and to determine the percentage of oil saturation from loss of weight in extraction or retorting tests. The small amount of residual petroleum left in a core sample affords but a poor basis for determining the gravity of the oil. A better result can generally be had by seeking a sample of the oil directly from the producing horizon with the aid of a formation tester (see page 561). However, the properties of the oil secured in a retorting test conducted as described in the foregoing section may be determined with a small pycnometer. By applying a suitable correction factor to the observed gravity, the probable density of the oil as it exists in the reservoir rock may be estimated. A considerable loss in A.P.I. gravity is suffered by the oil in the process of retorting. Thus, residual oil recovered in retorting may have a gravity of only 20 deg. A.P.I., whereas the gravity of the oil as it exists in the reservoir rock may be 40 deg. Tests may be made in the apparatus employed in retorting to determine the density loss suffered by a series of crude oils of different gravities. By comparison with such results, assembled in graphic form, the approximate corrected gravity of the oil condensed in the course of a retorting test may be estimated.[70]

Identifying Connate Water in Core Samples.—The water content of a core sample, as determined by extraction or retorting, may be connate water actually present in the pore spaces of the reservoir rock, or it may be water that has penetrated the core as a result of absorption of drilling fluid. Tests made by cutting cores in the presence of drilling fluids containing chemical reagents that can be identified in the water in the cores indicate that drilling fluid may displace oil in the outer portions of a core sample, but if the core is of large diameter and test samples are selected from the central portion, such water as is found to be present is likely to be connate water.[50]

Connate water is often characterized by high chloride content. Salinity of the connate water in a formation sample may be a matter of interest inasmuch as resistivity values recorded in electrical logs are influenced thereby. To determine the salinity of the water present in a core, a sample may be selected, crushed to separate the individual grains, and leached with a small amount of fresh water. After filtration of the leaching water from the sample, the filtrate is titrated to determine chloride content.

Identification of Hydrocarbon Oils as to Type.—The analyst will often wish to determine the character of the oil that he has extracted from the formation sample,

as described in the foregoing section. Although the expressions "paraffin base" and "asphaltic base" have no very definite meaning from the physical and chemical points of view, they have general significance in indicating the predominating constituents of an oil and serve in a general way to enable one to predict the character of the products that might be obtained from them. Greater value is usually attached to the paraffin oils than to the asphaltic oils, but this is not necessarily warranted in all circumstances.

If the oil is of paraffin base, continuation of the evaporation of the oil residue provided by the foregoing extraction test, to the point of dryness, will leave a plastic, waxy substance, generally yellow or light brown in color, which is impure paraffin. Such oils consist chiefly of hydrocarbons of the paraffin series (C_nH_{2n+2}), and are fully saturated—that is, they are incapable of combining with more hydrogen. Asphaltic-base oils yield a hard, lustrous, black residue on evaporation to dryness. They contain the naphthenes (C_nH_{2n}), benzenes (C_nH_{2n-6}) and other aromatic hydrocarbons. All of these are relatively unsaturated. Some oils of mixed base contain both the paraffin and asphaltic compounds in about equal proportions, in which case the presence of the former will be to some extent masked by the dark color and stiff consistency of the latter. The terms "paraffin base" and "asphaltic base" are thus seen to be somewhat indefinite, the name of the predominating series of hydrocarbons being applied. The chief difference between the two types is to be found in the heavier constituents.

Interesting differences may also be noted in the manner in which the different hydrocarbons react with the stronger acids. The paraffin hydrocarbons are not acted upon by concentrated fuming sulphuric acid, are not nitrated by nitric acid and are extremely resistant to all chemical reactions. The naphthenes are also resistant to acids, but the aromatic or benzene hydrocarbons are acted upon by nitric acid, forming nitrogenous products, while the olefin hydrocarbons are acted upon by concentrated sulphuric acid.

Determination of Permeability of Core Samples

The permeability of a rock sample is often a matter of interest as a measure of its capacity to transmit fluids through its pore spaces. For example, the permeability of a reservoir rock about a well determines the rate at which the well may produce. Permeability is inversely proportional to the flow resistance offered. It is measured by an arbitrary unit called the "darcy," named after Henry D'Arcy, a physicist who, in 1856, studied the flow of water through filter beds and proposed an empirical formula which has been found to express accurately the factors that enter into an expression of the pressure loss in flow of fluids through porous media. The D'Arcy formula may take various forms, depending upon the character of the fluid and the direction of flow. For horizontal flow of a liquid through a porous medium of uniform cross section, the following formula expresses the relationship of the several factors involved:[1]

$$K = \frac{uQL}{A(p_1 - p_2)}$$

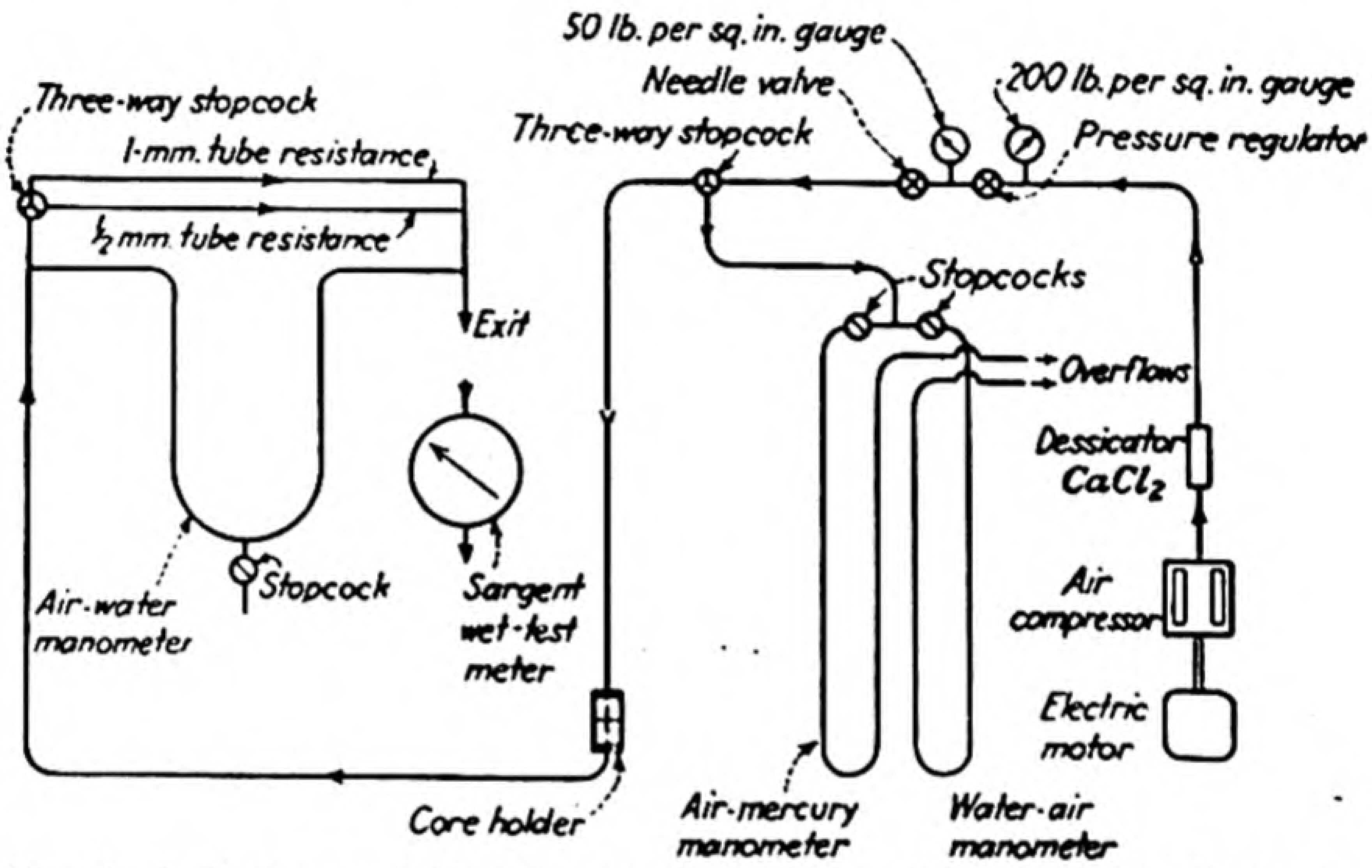
Here K is the permeability of the porous medium in darcys; u is the viscosity of the fluid in centipoises; Q is the volume rate of flow measured in milliliters per second; L is the length of the specimen in centimeters; A is the cross-sectional area of the specimen in a plane perpendicular to the direction of flow, in centimeters; p_1 is the pressure at the upstream face of the specimen; and p_2 is the pressure at the downstream face.

Where a gas is used as the flow medium, Q is the average volume rate of flow at the average pressure existing during flow through the specimen; or

$$K = \frac{2uQ_bPL}{A(p_1^2 - p_2^2)}$$

where Q_b is the volume rate of flow measured at atmospheric pressure P, in milliliters per second. The permeability coefficient K is an attribute of the porous medium and, theoretically, is independent of the fluid used in its measurement.

In routine laboratory determinations of permeability, a selected core sample is cut or trimmed to cylindrical or rectangular cross section A, and of such length L as may fairly be representative of the rock stratum that the sample represents. This is sealed in or fitted into a supporting metal or rubber core holder in such fashion that when the core and its supporting element are mounted in place in the permeameter, the flow medium (air, water or oil) will be forced to flow through the specimen under



(*After A. J. Carlson and M. Eastman in Am. Inst. Min. Met. Eng. Trans.*[5])

FIG. 286.—Flow diagram for permeameter using air as flow medium.

controlled pressure differential without leakage of the flow medium around the specimen. Uniform temperature conditions are maintained. The quantity of fluid passing through the specimen per unit of time thus becomes a measure of its permeability. A porous medium has a permeability of one darcy when the rate of flow through it, measured in milliliters per second per square centimeter of cross-sectional area, of a fluid of one centipoise viscosity, under a pressure or equivalent hydraulic gradient of one atmosphere (76 cm. of mercury) per centimeter, is unity. It is a further requirement that viscous flow conditions must obtain. The darcy is too large a unit for convenient comparison of relative permeabilities and it has become customary to express rock permeabilities in millidarcys.[69]

Permeameters.—An apparatus used in measuring permeability is called a "permeameter." Several different types of permeameters are used in laboratory measurement of rock permeabilities, but suitable equipment for this purpose must possess certain essential elements. There must be provided a closed system of tanks, pipes, valves and fittings from and through which the test fluid may flow under controlled pressure, through the specimen, to a receiving graduate or meter where its rate of flow may be measured (see Fig. 286). The test specimen must be supported in this flow circuit in such fashion that all fluid measured must pass through the specimen,

without leakage around it (see Fig. 287). Pressure gauges or manometers must be provided to indicate accurately the pressure at the upstream and downstream faces of the test specimen, and some means of controlling and regulating the upstream pressure of the test fluid is essential. A graduated cylinder or burette receives the fluid as it flows from the specimen if a liquid is used; or if a gas is employed, a meter of appropriate type and sensitivity will be needed to measure its volume. A stop watch enables the operator to determine the volume of fluid passing through the test specimen per unit of time. Thermostatic temperature control of the apparatus and the test fluid are essential for accurate work, and a thermometer is provided to indicate the operating temperature. Other supplementary aids include a barometer for observing atmospheric pressure and measuring devices for accurately determining the size of the specimen. If a liquid is used as the test fluid, it should be filtered to remove suspended solids before passage through the specimen. Dissolved gas which may be present in a liquid under pressure should be avoided; otherwise gas released from solution in bubble form may accumulate in the test specimen and influence the indicated permeability. Commercial types of permeameters embodying these essential features are now available, but in many oil-company test laboratories, specially designed and constructed permeameters are employed.[51]

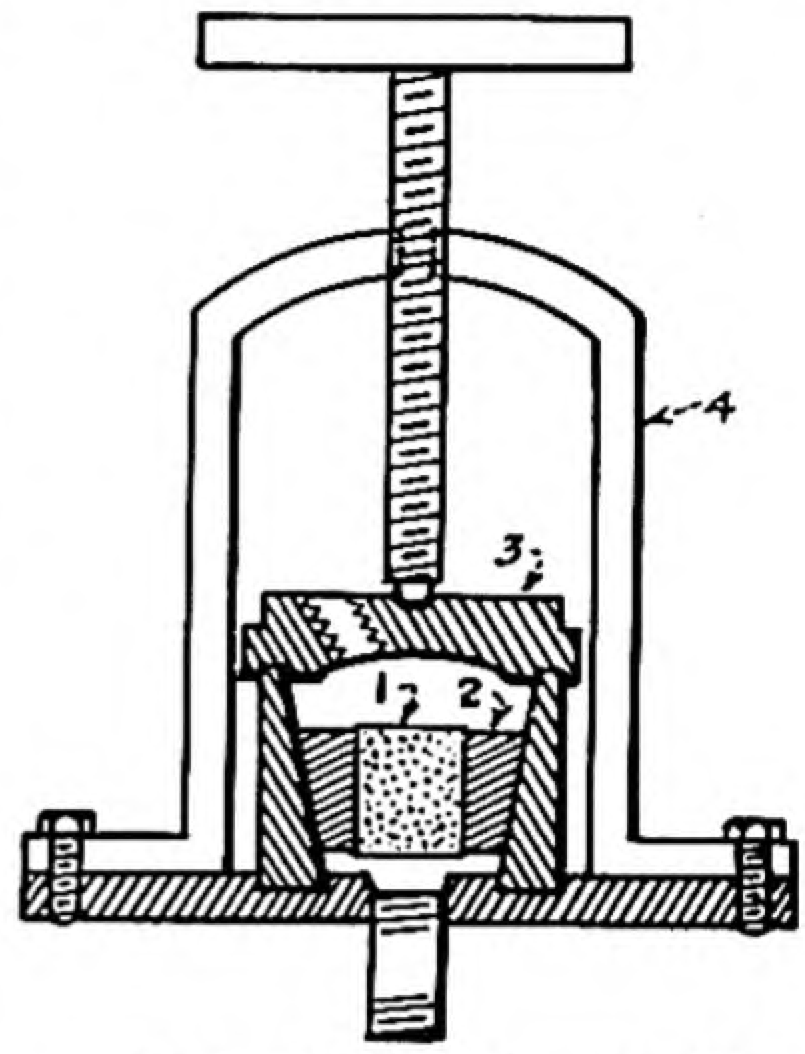


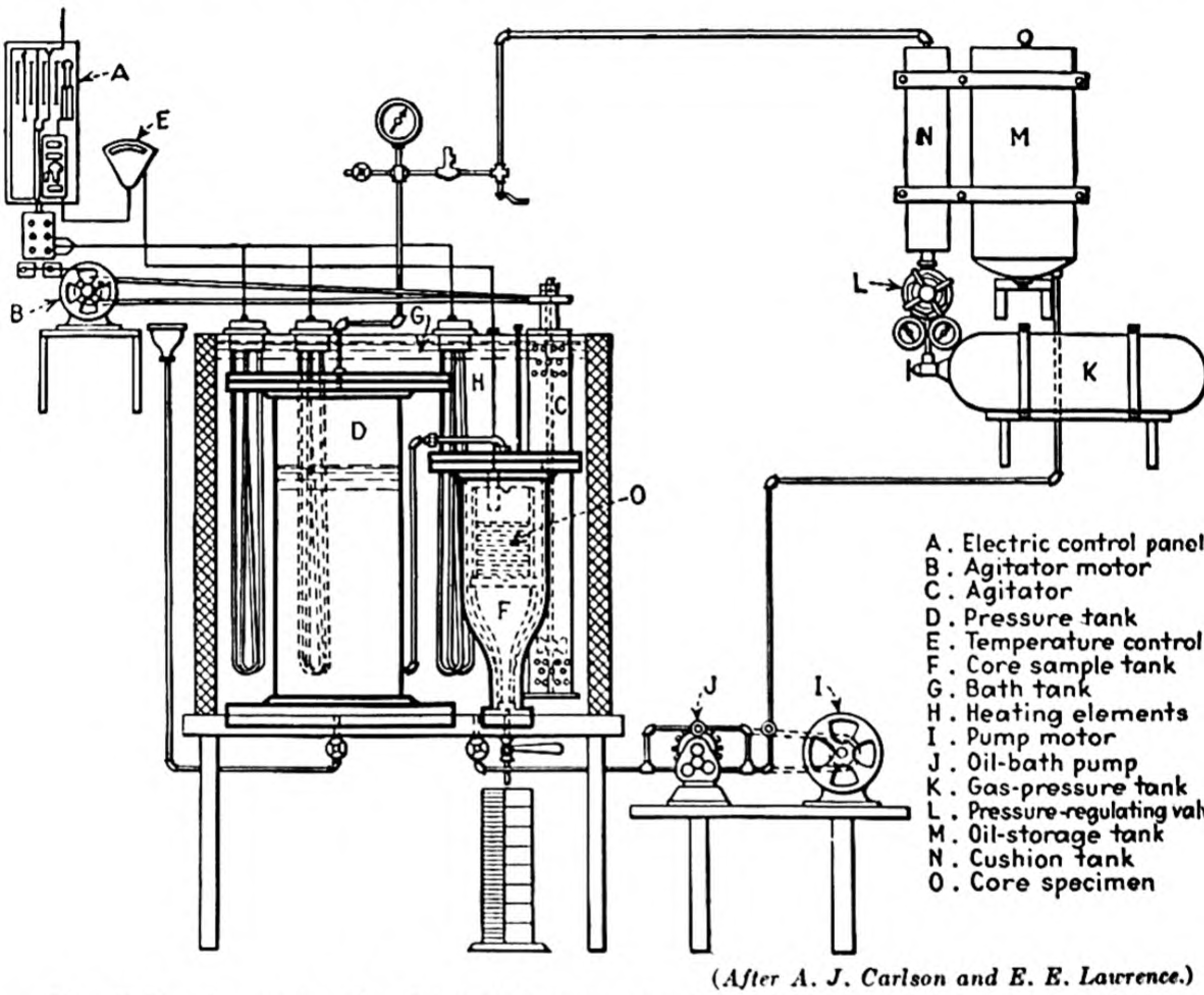
FIG. 287.—Core-holder assembly. 1, cylindrical core; 2, rubber stopper; 3, core holder; 4, supporting frame.

Typical of permeameters utilizing oil as the flow medium, the apparatus sketched in Fig. 288 is used in the petroleum laboratories of the University of California for making comparative permeability tests of core samples. The core section, a disk 1 in. thick, is accurately dressed and ground to fit snugly within a short pipe nipple. The space between the core *O* and the inner surface of the metal tube is filled with a cement which is impermeable to oil and holds the specimen rigidly in its position in the lower end of the nipple. Several different sizes of swaged nipples, concentrically mounted one within another, support the nipple containing the core and permit of adapting cores of different diameters. The larger of the nested swaged nipples is screwed into a tapped opening in the bottom of tubular chamber *F*, which is connected by communicating pipe fittings with oil reservoir *D*. A standard test oil nearly fills the oil reservoir, while gas pressure supplied from high-pressure storage tank *K*, governed by regulating valve *L*, maintains a constant, standard test pressure within chamber *F* and reservoir *D*. As pressure is applied, the test oil overflows into and fills chamber *F*, trapped air being vented through a pet cock. Both *F* and *D* are immersed in an oil bath which is maintained at a standard test temperature by three thermostatically controlled heating elements *H*. Circulation of the oil bath is accomplished by a small motor-driven stirring device. The quantity of oil flowing through the specimen per minute per unit of cross section, as measured in a receiving cylinder, is taken as a measure of the comparative permeability of the specimen.[8]

Mounting the Test Specimen.—Among the problems involved in operation of all permeameters is that of mounting the test specimen in the supporting element so that leakage of the test fluid may not occur around the specimen. Two methods of preventing this are commonly employed. One involves use of a suitable wax or cement that may be placed around the specimen while in fluid condition, soon to harden and completely fill the annular space between the specimen and the supporting element. The alternate method involves supporting the specimen in a snug-fitting stopper of

soft rubber, or surrounding it by a sheath of rubber which is caused to press tightly against the outer surface of the specimen by exterior pressure. Where an oil is used as the test medium, a variety of synthetic rubber resistant to oil decay should be used. Where a cement or wax is used, care should be taken in its application that it does not penetrate the pore spaces of the specimen or overflow the rock faces exposed to fluid flow.

Choice of the Flow Medium.—As previously indicated, the test fluid may be either a liquid or a gas. Air, water and oil have been widely used for this purpose, but the trend has lately been toward use of instruments that employ air. Water is objectionable inasmuch as it may result in hydration of clay and shale that may be



(After A. J. Carlson and E. E. Lawrence.)

FIG. 288.—Apparatus for determining comparative permeabilities of core specimens.

present in the test specimen, causing swelling and reduction of pore space and permeability. From some points of view, oil should be preferable to air as a test medium, but a permeameter designed for use of oil is more costly and less rapid in use, and problems incidental to determining viscosity of the medium and avoiding clogging tendencies from presence of fine suspended solids and gas bubbles are troublesome. It would appear that the stationary film of oil that adheres to the mineral grain surfaces would reduce to some extent the apparent permeability of the specimen when oil is used as the flow medium and, inasmuch as this is the condition that obtains in oil reservoirs, some authorities prefer oil to air. Apparently, however, the difference is slight and the greater convenience and rapidity possible with the air permeameter commend it to most analysts.

Laboratory Procedure in Making Permeability Tests.—The size and form of the test specimen prepared for determination of permeability will depend upon the

requirements imposed by the permeameter to be used, and more particularly by the form and size of the core holder. Often the permeameter is designed to receive test specimens of cylindrical form, in which case they may be 1 cm. or more in length and will have a cross-sectional area of 2 to 10 sq. cm. Specimens will be carefully cut from representative portions of the larger core samples, preferably with the aid of a small diamond core drill, and may be cut at right angles to or parallel with the bedding planes as the purpose of the test may require. Perhaps a separate test specimen will be cut in each direction; or a specimen may be cut in cubic form so that it can be tested first with flow of fluid along bedding planes and later with flow across bedding planes.

After dressing the test specimens to proper size and form, they are subjected to extraction in a Soxhlet extraction apparatus and thoroughly dried to remove all liquids from the interstitial pore space. The dimensions of the specimen are carefully measured and it is then mounted and sealed in the supporting element and inserted in operating position in the permeameter. If maximum accuracy is required, flow tests are made at several different pressure differentials, and for each test the rate of flow and the pressures at the upstream and downstream faces of the test specimen are observed and recorded.

Computation of Permeability.—The value of the permeability index K is computed for each rate of flow with the aid of one or another of the formulas on pages 677–678, and values of K are then plotted against the reciprocals of the mean pressures. If a gas permeameter is used, variation in the values of K will be noted, K varying as a linear function of the reciprocal of the mean pressure at which the test is conducted as long as conditions are within the range of viscous flow. Also, the resulting values of K will vary with the nature of the gas used. The preferred value for K is found by extrapolating the permeability graph to infinite pressure (*i.e.*, reciprocal of mean pressure = 0). So determined, the permeability obtained by using gas as the flow medium is equivalent to that computed from measurements made with a liquid as the flow medium. For approximate results, which are usually justified in view of the variation in lithologic properties of rock samples, one or two determinations of permeability at different flow rates will ordinarily be sufficient when using a liquid test medium. It is seldom that one may feel justified in reporting permeabilities in millidarcys with more than three significant figures.

American Petroleum Institute Code No. 27 offers the following examples of the method of applying the D'Arcy formula and computing permeabilities from observed permeameter measurements on a sample of Wilcox sandstone from a Mid-Continent field:[1]

Dimensions of cylindrical sample: Diameter = 1.905 cm.; cross-sectional area = 2.85 sq. cm.; length = 2.54 cm.

Test Data: With a liquid permeameter, using water as the flow medium, average rate of flow = 0.702 ml. per sec. per sq. cm. of cross section; average pressure gradient = 1.1 atmospheres per cm. of length; viscosity of water at test temperature = 0.884 centipoise.

$$\text{Permeability } K = \frac{(0.702)(0.884)}{1.11} = 0.555 \text{ darcy} = 555 \text{ millidarcys}$$

With a gas permeameter, using air as the flow medium: average rate of flow at mean pressure = 12.3 ml. per sec. per sq. cm. of cross section; average pressure gradient = 0.400 atmosphere per cm. of length; viscosity of air at test temperature = 0.0182 centipoise.

$$\text{Permeability } K = \frac{(12.3)(0.0182)}{0.400} = 0.559 \text{ darcy} = 559 \text{ millidarcys}$$

Another approach to the determination of the value of the permeability constant K, when a gas is used as the flow medium, is provided by plotting the values of Q/A against the corresponding values of $(p_2 - p_1)/L$. If flow is viscous, this should result in a line of constant slope through the origin of coordinates. The slope of this line, expressed mathematically, is equal to K/u. If Q_b is the volume rate of flow, measured at base pressure p_b, values of Q_bp_b/A are plotted against values of

$$\frac{(p_1^2 - p_2^2)}{2L}$$

and again the result should be a straight line through the origin of coordinates, and the slope of this line is equal to K/u. In either case, if the flow is not viscous, the line will not be a straight line.

Determination of Porosity of Core Samples

The porosity of an oil reservoir rock is one of its important lithologic properties. On this factor depends the storage capacity of the reservoir for oil and gas. The rate of oil production under a given reservoir pressure will also be influenced by this property. A knowledge of porosity will therefore provide a useful basis for estimates of residual oil content, of pressure conditions necessary to cause movement of fluids and of potential rates of production.

The porosity of a rock specimen is defined as the ratio of the aggregate volume of its void spaces to its gross bulk volume. It is usually expressed as percentage porosity, thus,

$$\text{Per cent porosity} = \frac{\text{pore volume}}{\text{bulk volume}} \times 100$$

For some purposes, it is found convenient to distinguish between total porosity and effective porosity. The latter is a measure of the ratio of the volume of communicating pore space of a rock specimen to its gross bulk volume. It, too, is expressed in percentage. The term "communicating pore space" excludes pore spaces frequently present in rocks that are completely isolated from surrounding pore spaces, usually by processes of secondary cementation. It is not a term of absolute value, for the ability of a fluid to pass from pore to pore of a containing rock will be largely a matter of the pressure applied. Partly sealed pores may permit passage of fluids at very high pressure, but not at low pressure.*

As indicated by the equation given above, to evaluate the percentage of porosity in a rock specimen, means must be found for quantitatively determining (1) the bulk volume of the specimen and (2) the volume of the pore spaces within it. There are several different ways of determining each of these factors, and most of the methods produce closely comparable results. A device used for this purpose is called a "porosimeter."

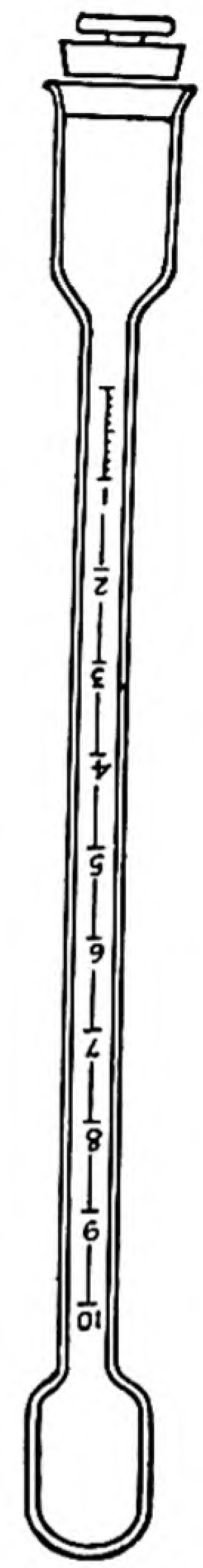
Methods of Measuring the Bulk Volume of Rock Specimens.—Measurement of bulk volume may be done (1) by immersion in a liquid, such as mercury, which does not enter the pore spaces of the specimen, and measuring the increase in volume of the liquid; (2) by saturating the pore space with a liquid, such as acetylene tetrachloride, then immersing the specimen in a measured volume of a fluid and noting the increase in apparent volume of the fluid; (3) by coating the specimen with a water-impervious substance which does not enter the pore space of the specimen,

* Uren, L. C., Inspection and Analysis of Formation Samples: Determination of Porosity and Grain Size Distribution, *Petroleum Engr.*, June, 1943, pp. 51–60.

then weighing the coated specimen, first in air and then in water, and computing the volume from the known density of the water and the loss of weight when immersed in water. (4) If the specimen is dressed to some regular geometrical form, such as a cube, its bulk volume can be computed directly from its measured dimensions. (5) If the volume of the pores and specific gravity of the mineral substance of which the specimen is composed are known, the bulk volume can be computed from the dry weight of the specimen.

Determination of Bulk Volume by Mercury Displacement. This is one of the most commonly used methods of determining bulk volume, especially when the sample is sufficiently well cemented so that it does not disintegrate readily. Owing to its very high surface tension, mercury does not readily "wet" or enter the pore spaces of a rock specimen immersed in it. Taking advantage of this peculiarity of mercury, we may determine the bulk volume of a rock specimen in either of three ways: (1) by determining the dry weight of the sample in air, then determining the weight necessary to immerse it in mercury (the bulk volume may be calculated by dividing the sum of the two weights by the specific gravity of mercury); (2) by filling a pycnometer of accurately determined volumetric content with mercury, then inserting the test specimen and measuring the volume of mercury displaced; (3) by partly filling a graduated burette with mercury, immersing the rock specimen in it and noting the increase in apparent volume of the mercury.

A convenient device utilizing the latter method is described by Pyle and Sherborne.[51] This consists of a graduated glass volumeter with a closed bulb at one end and enlarged at the other open end which is fitted with a ground-glass stopper (see Fig. 289). The tube is partly filled with mercury, the stopper inserted and held securely in position while the tube is turned upside down. With the volumeter in this position, the volume of mercury in it is observed by reference to the graduations. The volumeter is again turned so that the stopper end is uppermost, the stopper removed and the rock specimen inserted in the open enlarged end. The stopper is again pressed securely in position, the apparatus again inverted and the apparent volume of mercury again observed. The apparent increase in volume of the mercury is the volume of the rock specimen.



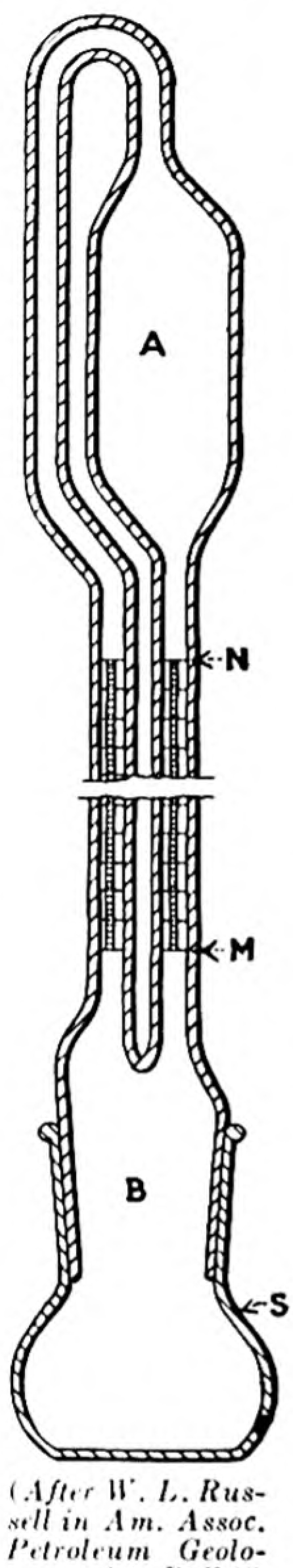
(After Pyle and Sherborne, Petroleum Development and Technology, Am. Inst. Min. Met. Eng. Trans.[51])

FIG. 289.—Mercury volumeter used in determining bulk volume of formation samples.

Determination of Bulk Volume by Fluid Displacement of a Saturated Rock Specimen.—Utilizing this principle, we may differentiate between (1) methods that make use of a liquid as the displacement medium and (2) methods that make use of a gas as the displacement medium.

W. L. Russell[55] has described an apparatus and a method that are widely used in determining bulk volume, which make use of a special form of volumeter or pycnometer and employ acetylene tetrachloride as the displacement and pore-saturation medium. This fluid readily enters and completely fills the pore spaces of a rock specimen. Kerosene or tetrachlorethane, or any other liquid of low viscosity that "wets" the sample freely, may be used instead of acetylene tetrachloride. The special form of pycnometer used, illustrated in Fig. 290, consists of two graduated tubes which are enlarged at one end to form reservoir A, while at the other end they are connected by reservoir B. The glass tube forming the latter

is ground on its exterior surface and is provided with ground-glass stopper *S*. The apparatus is so constructed that when the stopper is in place, as shown in the sketch, the volume below the point *M* on the graduated tubes is equivalent to that above the uppermost graduation *N*. In making a bulk-volume test with this apparatus, the rock specimen is first immersed in acetylene tetrachloride in a separate container from which air is exhausted by a vacuum pump until air bubbles cease to issue from it. The saturated specimen is then removed, the liquid adhering to its outer surface is wiped off, and it is then placed in reservoir *B*, this end of the pycnometer being held uppermost with stopper *S* removed and the apparatus filled to mark *N* with acetylene tetrachloride. Stopper *S* is then placed in position with the ground surfaces greased to prevent leakage, and the pycnometer is inverted to the position shown in Fig. 290. The apparent increase in volume of the fluid in the pycnometer may then be determined directly by reference to the graduations on the tubes between *M* and *N*. This is taken as the bulk volume of the specimen.



(*After W. L. Russell in Am. Assoc. Petroleum Geologists Bull.*[55])

FIG. 290.—Special form of pycnometer used in determination of porosity of sandstone by the acetylene-tetrachloride method.

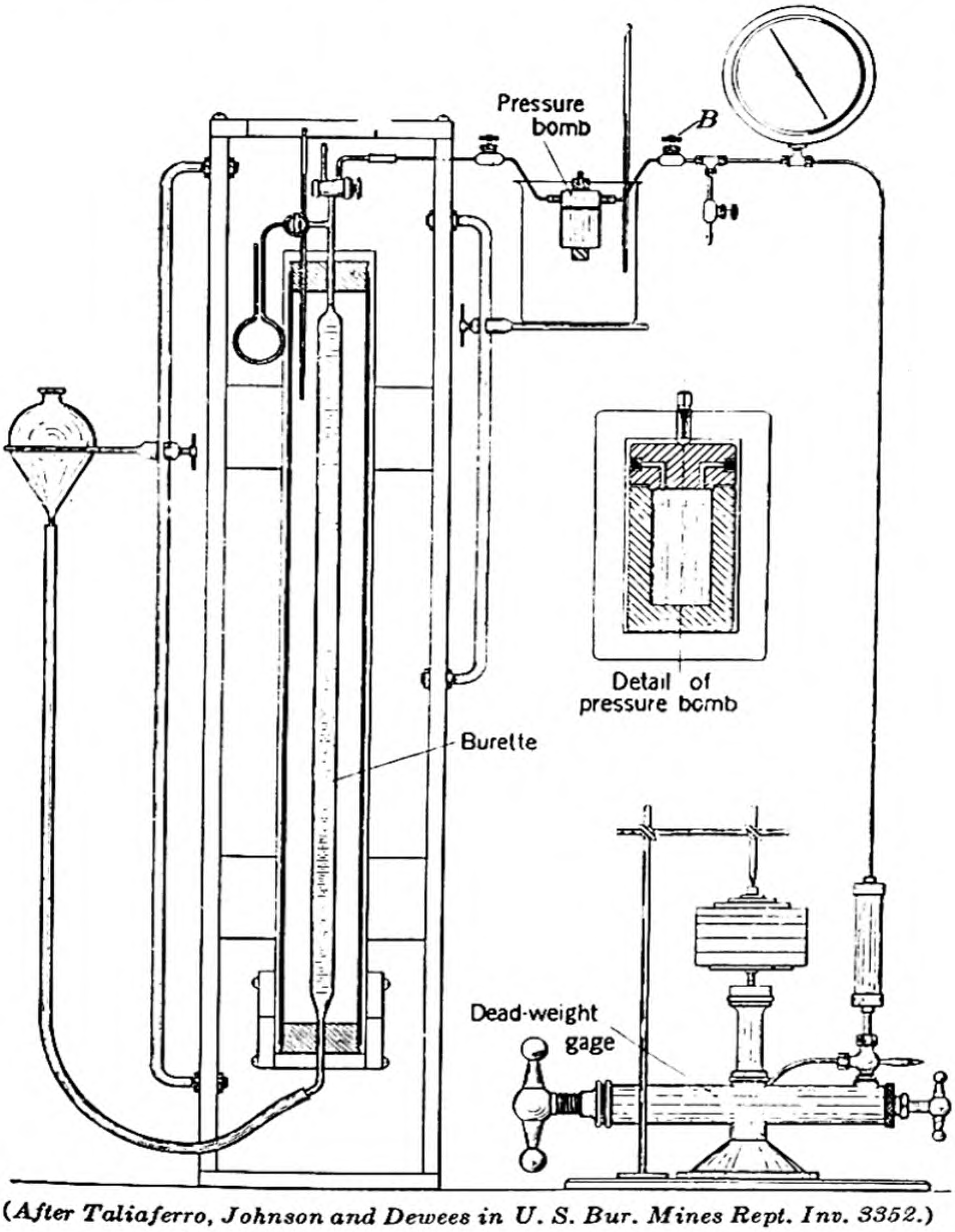
Porosimeters, designed primarily to determine the volume of the mineral content of a specimen rather than the bulk volume, can be used for the latter purpose by dipping the specimen in molten paraffin, thus sealing the interior pore space against contact with exterior fluids. For example, the hydrogen porosimeter described below may be used in this way. In this device, a gas such as hydrogen is charged under pressure of several atmospheres into a steel bomb containing the paraffin-coated specimen. The gas so imprisoned is then allowed to expand into a second container to a lower pressure. Known volumes of the intercommunicating containers and the indicated gauge pressure before and after expansion provide a basis for computation of the volume of the specimen. A bulk-volume test of this character can best be made after a test in the same apparatus and with the same specimen to determine the volume of the mineral substance of the specimen, as explained in a later section. Correction for the volume of the paraffin, determined as described in the next section, is subtracted from the apparent volume of the specimen.

Determination of Bulk Volume of a Rock Specimen by Coating with Paraffin and Weighing in Air and Water.—A method developed by A. F. Melcher[41] involves first coating the specimen with molten paraffin, then weighing the coated specimen in air and later in water by suspending it from a beam of a balance with a fine silk thread or wire. Weighing both before and after coating provides a means of determining the weight of the paraffin adhering to the specimen, and from its known density (0.906) the volume of the paraffin may be computed. The loss of weight of the specimen while immersed in water, in comparison with its weight in air, is a measure of the weight and volume of the water displaced. The volume of water displaced, less the volume of the paraffin coating, is the bulk volume of the specimen.

Determination of Bulk Volume from Weight, Specific Gravity and Pore Volume of a Rock Specimen.—If a specimen is of some pure mineral substance the specific gravity of which is known (*i.e.*, quartz, which has a specific gravity of 2.65), to determine the volume of the mineral substance, we have but to determine the dry weight of the

sample and divide it by the specific gravity. Then, if the volume of the pore space can be determined by one or another of the methods described below, the bulk volume is equal to the sum of the pore volume and the mineral volume.

Methods of Measuring the Volume of the Pore Space in a Rock Specimen.—The volume of the pore space within a rock specimen can be determined indirectly by measuring the bulk volume and mineral substance volume. Substracting the volume of the mineral substance from the bulk volume gives the volume of the pores. We



(*After Taliaferro, Johnson and Dewees in U. S. Bur. Mines Rept. Inv. 3352.*)
FIG. 291.—Gas (Boyles' law) porosimeter.

may determine the volume of the mineral substance in either of several ways: (1) by gas displacement; (2) by comparison of the dry weight of the specimen with the weight when saturated with and immersed in a liquid of known density; (3) by comparison of the dry weight of the specimen with its weight when saturated with a liquid of known density; and (4) by crushing the sample to separate the individual grains and then determining their volume by weighing them in a pycnometer of known volume.

Determination of the Volume of the Mineral Substance of a Rock Specimen by Gas Displacement.—The so-called "Bureau of Mines" or "Boyles' law" porosimeter, commercially available, comprises a steel bomb with facilities for filling it with gas

under closely controlled pressure, and then measuring the volume of gas by expansion into a graduated burette (see Fig. 291). A gas, such as hydrogen, is charged into the empty bomb to a pressure of four or five atmospheres and then expanded by releasing it gradually to the graduated burette where its volume is accurately measured. A duplicate test is then made with the mineral specimen in the bomb. As the pore space of the specimen is penetrated by the gas, the difference between the volumes of gas so determined is a measure of the volume of the mineral grains of which the specimen is composed.[62]

Determination of the Volume of the Mineral Substance of a Rock Specimen by Comparison of Its Dry Weight with Its Weight When Saturated with and Immersed in a Liquid of Known Density.—The volume of the mineral substance in a rock specimen may be computed by subtracting, from the dry weight of the specimen in air, its weight when suspended on a slender thread or wire from the beam of a balance in a liquid which freely enters its pore spaces. The difference between these two weights is a measure of the weight of the fluid that the mineral substance displaces. From this, if the density of the fluid is known, we may compute the mineral volume. Kerosene or acetylene tetrachloride may be the liquid used and, to avoid imprisoned air bubbles in the specimen, it may be saturated with the liquid in a closed vessel from which the air has been partly evacuated by a vacuum pump.

Determination of the Volume of the Mineral Substance of a Rock Specimen by Comparison of Its Dry Weight with Its Weight When Its Pore Spaces Are Saturated with a Liquid of Known Density.—We may compute the volume of the pore space in a rock specimen by first weighing it while dry in air, then saturating the pore space of the specimen with a liquid of known density and weighing again. Subtracting the dry weight from the saturated weight, we obtain a figure which represents the weight of the fluid filling the pore spaces and, if we know the specific gravity of the fluid, we may compute its volume. A liquid of low viscosity that freely wets the mineral surfaces and penetrates the pore spaces—such as kerosene or acetylene tetrachloride—should be used, and precautions taken to avoid imprisonment of air bubbles in the pore spaces by conducting the saturation in a closed vessel from which the air has been partly evacuated. If we wish to know the volume of the mineral substance, we may subtract the volume of the pores, thus determined, from the bulk volume; but in computing percentage porosity this will be unnecessary if we can determine the volume of the pores directly.

Determination of Volume of the Mineral Substance in a Rock Specimen by Crushing to Separate Its Individual Grains and Weighing Them in a Pycnometer of Known Volume Filled with Liquid of Known Density.—After the bulk volume of a specimen has been determined by one or another of the methods described above, it is crushed in a mortar to release its individual grains from each other. The mineral fragments are then thoroughly washed in a volatile oil solvent, dried and weighed in a pycnometer of known volume. A liquid of known density, such as kerosene, is then poured into the pycnometer containing the sample until it is full, the perforated stopper is inserted, the outside of the pycnometer wiped free of excess fluid and the weight again determined. The difference between the two weights will be the weight of the fluid added to fill the pycnometer, from which the volume of the fluid may be determined if its density is known. This volume is then subtracted from the volume of the pycnometer to determine the volume of the mineral grains.

Determination of Volume of the Mineral Substance in a Rock Specimen by Dividing the Weight of the Specimen by Its Average Specific Gravity.—An approximate calculation of the volume of the mineral substance in a rock specimen may be made simply by determining its dry weight and dividing by the average specific gravity of the mineral. The latter figure, of course, will ordinarily not be known with

certainty, but it may often be assumed to be approximately that of quartz (2.65). Most sands and sandstones are composed largely of quartz and most common rock-forming minerals have specific gravities that do not differ greatly from that of quartz.

Determination of Effective Porosity and Total Porosity.—The total porosity of a rock specimen may ordinarily be determined only by crushing it to separate its component grains, then determining the volume of the grains and subtracting this volume from the bulk volume of the specimen. The effective porosity or the volume of the communicating pores may be determined by any of the methods of measuring the volume of the pore space without crushing the specimen.

Determining Size Distribution of Granular Components of Formation Samples

The size of grains composing sand or sandstone strata is often of interest in correlation of formation samples from near-by wells or in recording their lithologic properties for other purposes. Coarse-grained sands and sandstones generally yield their fluid content more rapidly than fine-grained rocks, and the preponderating size of grain and range of grain sizes have an important influence on rock permeability. Laboratory inspection of a formation sample to determine the size distribution of its component grains involves disaggregation of the sample in such a way as to release the grains from each other without crushing them to smaller fragments, and then subjecting a weighed sample of the disaggregated material to a process of screening or water classification. The percentages by weight of granular rock fragments, segregated within different size ranges, afford a basis for appraisal of grain-size distribution.

Disaggregation of Granular Rock Specimens.—The procedure to be followed in disaggregating a rock specimen will depend upon the extent of induration and character of the cementing material. Some sand specimens will crumble under pressure of the fingers; others can scarcely be broken under blows from a hammer. Often a laboratory mortar and pestle may be used advantageously, but methods involving impact or grinding forces are apt to abrade the mineral grains, reducing them to smaller size and destroying their native texture and crystalline form. Alternate heating and plunging in cold water will cause some rocks to disintegrate. Other methods of disaggregating specimens involve use of fluids that enter the pore spaces and expand as they solidify or freeze, and methods involving use of solvents to dissolve the cementing materials that bind the grains together.

Repeatedly saturating the pore spaces with water and freezing the saturated specimen in a refrigerator, then thawing, will disaggregate most granular rocks. Substances that melt in their own water of crystallization, such as sodium acetate or sodium thiosulphate ("hypo"), may also be used. Dry fragments of the specimen are placed in a suitable container with an equal amount of the crystallized reagent, a few drops of water are added and heat is applied until the crystals melt and enter the rock pores. On cooling, a few crystals of the reagent are added, recrystallization occurs and the resultant expansion disintegrates the rock specimen. It may be necessary to repeat the process several times before disaggregation is complete.

If the cementing material binding the mineral grains together is carbonate of lime, and the grains are siliceous in character, washing with dilute hydrochloric acid will dissolve the cementing material and release the grains. A dilute acid wash is also helpful in removing from the mineral grain surfaces incrustations of other secondary materials, thus facilitating lithologic inspection and identification of mineral properties under the microscope.

Leaching with Solvents to Remove Residual Oil.—Prior to screening, residual oil that may be present in disaggregated samples should be thoroughly removed: otherwise the mineral grains will tend to adhere to the screens or to each other. This may be done by repeated washing or leaching with a suitable solvent, such as carbon tetrachloride or ether. A Soxhlet extraction apparatus may be used for this purpose (see page 673), or a small bowl-type centrifuge such as the Dulin Rotarex (see page 674). After washing or leaching, the sample must be thoroughly dried, preferably by heating for a time at a temperature of less than 210°F. in an electric oven.

Screen Sizing of Disaggregated Formation Samples.—The usual method of determining grain-size distribution is to classify a weighed amount of the component grains of the disaggregated sample by screening through a series of nested screens of appropriate sizes. The percentage of the total sample, by weight, retained on each screen provides an index of the grain-size distribution. Screens employed for this purpose are constructed of brass-wire mesh or, in the finer sizes, of silk fabric, mounted in shallow cylindrical pans 6 to 12 in. in diameter. Tyler standard screens are commonly used, ranging from 10 to 200 mesh. For very fine material, a 325-mesh screen is also available. The Tyler screen scale is so designed that the width of each successive screen opening in the series is 1.414 (*i.e.*, $\sqrt{2}$) times the width of the opening in the next smaller size. Table XLIII gives the sizes of screen openings in the Tyler standard screen scale.

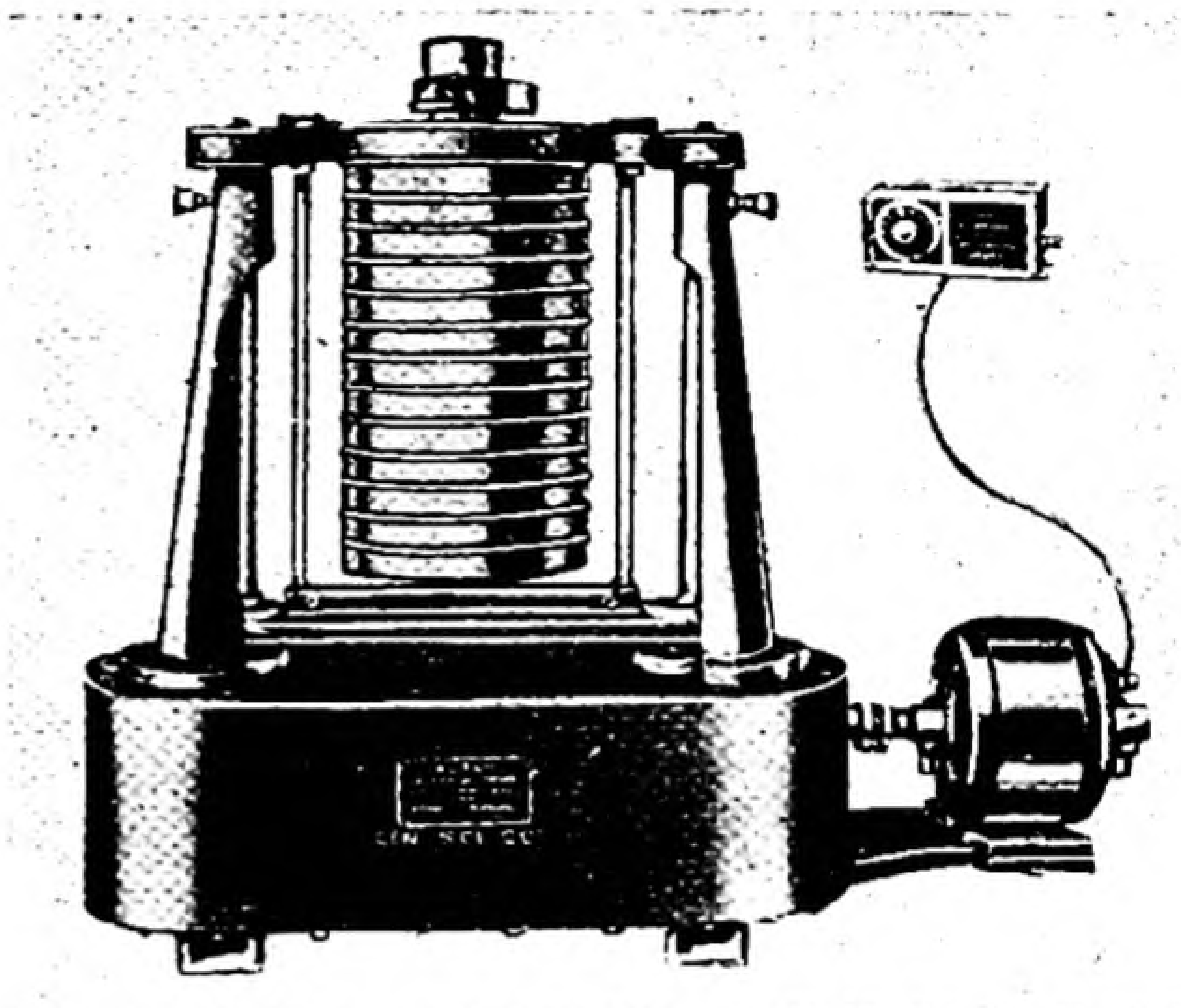
TABLE XLIII.—SIZES OF SCREENS IN THE TYLER STANDARD SCREEN SCALE

Mesh	Size of screen openings	
	Inches	Millimeters
10	.065	1.651
14	.046	1.168
20	.0328	.833
28	.0232	.589
35	.0164	.417
48	.0116	.295
65	.0082	.208
100	.0058	.147
150	.0041	.104
200	.0029	.074
325	.0017	.044

In conducting a screening test, the screens are nested in the order of size, with the coarsest screen on top. An accurately weighed portion of the disaggregated, washed and dried sample is placed in the upper pan, the screen cover is placed in position on top and a receiving pan on the bottom of the pile of nested screens, and the assembly shaken with an undulating, circular motion. In order that comparative results may be obtained, a standard procedure should be developed governing the time, manner and vigor with which the screens are shaken. Hand methods are laborious and likely to be erratic in these respects, so it is considered better to employ mechanical shaking devices that have been developed for this purpose. For example, the Ro-Tap testing-sieve shaker, illustrated in Fig. 292, assures that each sample will be subjected to precisely the same treatment. This machine reproduces the circular motion given testing sieves in hand screening and provides, in addition, a

vertical vibrating force that prevents the screens from clogging. Because of the uniform mechanical action, comparable results are thus attained in successive tests. With such an appliance, the whole process of screening can be standardized to a degree not possible in hand screening.

After screening, the component fractions of the sample will be found segregated on the various screens in accordance with their respective sizes. After the nested screens have been separated, the material retained on each is carefully collected and weighed and its percentage of the gross weight of the original sample is computed. Results may then be conveniently tabulated with a view toward convenient use.



(*Courtesy of Central Scientific Co.*)
FIG. 292.—Ro-Tap testing-sieve shaker.

Determination of Size Distribution of Granular Mineral Particles by Water Classification.—Other alternative methods of size classification include elutriation and determination of the rate of settling in water. An elutriator provides a vertical tube through which a liquid, such as water, flows upward with controlled velocity. If the disaggregated sample is of uniform density, particles above a certain size will sink in the ascending stream of fluid, while smaller particles will be swept upward, caught in a settling chamber, collected, dried and weighed. By varying the rate of ascending velocity of the fluid in successive tests, "crops" of different sizes may be segregated. Calibration of the instrument may determine the rate of flow of the fluid to segregate a component of a given maximum size. Repeated elutriation of the heavy crops will provide data for a complete size-distribution analysis.

Differences in the rate of settling of mineral particles of varying sizes in a stationary column of water or other liquid may provide data for a grain-size analysis of a disaggregated formation sample. Stokes' law, which is found to govern in such a system, providing we do not enter the realm of hindered settling, states that

$$r^2 = \frac{9}{2}\frac{uh}{(M - L)gt}$$

where r is the radius of the settling particle in centimeters; u is the absolute viscosity of the liquid in poises; h is the distance settled in centimeters; t is the time in seconds for the particle to sink h cm.; M is the density of the mineral; L is the density of the liquid; and g is the acceleration of gravity (980 cm. per sec. per sec.).

Stokes' law holds only for particles of spherical form which, of course, seldom exist in nature. The shape of the mineral particles will influence their rate of settling, flaky, platy particles settling less rapidly than rounded forms. Water-classification methods are tedious and difficult, and are recommended for use only in size analysis of mineral particles too small for effective screening—*i.e.*, less than 200 mesh.

IDENTIFICATION OF DISAGGREGATED MINERAL CONSTITUENTS OF FORMATION SAMPLES

The mineral constituents of formation samples consist for the most part of grains of quartz, feldspar, hornblende, mica and other common rock-forming silicates.

Less common minerals, however, are often present, occasionally in sufficient amount to characterize the particular horizon from which the sample is taken. The preponderance of one mineral or another, or unusual associations of various minerals, or the presence of rare minerals will often provide a means of identifying a particular stratum and of correlating it from well to well.

The color of a formation sample is often an index of the nature of the prevailing mineral constituent. Thus, a pure white crystalline sand of vitreous luster is generally composed largely of quartz, while other light-colored sands often contain large percentages of the feldspars or granular limestone or dolomite. Reddish or yellowish sands will usually be found to be stained with a secondary coating of iron oxide. Green sands often contain important amounts of epidote, olivine and other secondary minerals derived from the less persistent primary silicates. The color of a sample will usually be more pronounced when it is wet.

Sand grains are often coated with secondary minerals which tend to mask their true color, transparency and crystalline form. Boiling in a dilute solution of hydrochloric acid (commercial HCl diluted with an equal amount of water) will remove much of this surface material, leaving the siliceous mineral grains in a condition that facilitates their subsequent identification by petrographic inspection under the microscope. Familiarity with the color, crystalline form, texture and cleavage of the common rock-forming minerals will enable the observer to identify quickly the mineral grains under a binocular microscope. Absolute identification of the various minerals may be made only by the more tedious methods designed to determine the refractive index, birefringence, crystallographic form, color, pleochroism, interference figure and other properties with the aid of a petrographic microscope.

Still other technics, as yet not fully developed or applied in the inspection of formation samples, involve not only identification of the minerals present, but studies of the shape of grains, character of grain surfaces and nature of secondary cementing materials that disclose the life history of the specimen and the character of sedimentation that was responsible for its formation.[19]

Heavy Mineral Concentration and Identification in Formation Samples.—A large percentage of the mineral components of most formation samples consists of ordinary rock-forming minerals of low or medium density. In many samples, however, there will also be present smaller amounts of less common minerals of high density that may be a peculiar characteristic of the strata from which they come. Such minerals as chromite, chlorite, muscovite, biotite, zircon, garnet, tourmaline, rutile, titanite, glaucophane, epidote, hornblende, augite, actinolite, barite and anhydrite are seldom predominant minerals in a formation sample, and in the aggregate may represent but a few per cent of the total mass of the sample. Yet, one or another of these minerals may be present in abnormal amounts, or the assemblage of these less common minerals may present certain characteristic ratios. If this is found to be the case, such an occurrence will often be a valuable index for correlation of formations within areas of limited expanse, and to differentiate an individual stratum in the section from those above or below it.

Because of the small amounts of such minerals commonly present, they are obscured and their identification made difficult by the presence of much larger amounts of the lower density minerals. Any process of concentration that will segregate some of the mineral components, particularly the minerals of higher density, will therefore facilitate their identification. Methods of concentrating various components include the following technics: (1) heavy mineral concentration by gravitational segregation with the aid of heavy liquids; (2) magnetic separation of minerals possessing magnetic susceptibility; (3) dielectric separation of minerals; and (4) electrostatic separation of minerals.

Heavy-Mineral Concentration by Gravitational Segregation with the Aid of Heavy Liquids.—A convenient method of separating the lighter from the heavier mineral grains in a disaggregated sand or sandstone formation sample involves floating the lighter mineral-grain components on a heavy liquid through which the heavier grains will sink. Either of several different heavy liquids may be used for this purpose, among which are bromoform, acetylene tetrabromide, stannic bromide, antimony tribromide, thallium formate and mixtures of mercuric chloride and mercuric iodide. Of these, bromoform ($CHBr_3$) (density 2.89) and acetylene tetrabromide (density 2.96) are most useful. By dilution with benzene or carbon tetrachloride, liquids of lower density may be prepared with these reagents if desired.[60]

Bromoform is less expensive than other heavy liquids and is generally preferred for heavy mineral segregation. It is commercially available, chemically inert, nonpoisonous and can be recovered and purified from filtered residues for further use. Separation of the light and heavy mineral crops is conveniently effected in a separatory funnel or porcelain evaporating dish, stirring the mixture of disaggregated mineral fragments and bromoform to facilitate segregation. If a separatory funnel is used, the heavy crop that has settled in the bottom of the funnel is drained away into an ordinary funnel and caught on filter paper through which the residual bromoform is washed with alcohol. The heavy crop, often representing less than 1 per cent of the total mass of the formation sample, is then dried and is ready for microscopic inspection.

Identification of the various minerals present in the heavy mineral aggregate may be effected by one skilled in petrographic methods, either by sight inspection under the binocular miscroscope or by analytical procedures with the petrographic microscope. A count is made at random of, say, 100 mineral grains, and the percentage of each mineral is recorded. Interest may center on abnormal amounts of a particular mineral or on the variety and percentages of different minerals in the assemblage.

Separation of Heavy Minerals Possessing Magnetic Susceptibility.—Minerals vary in susceptibility to magnetic influences. Some, like magnetite, pyrrhotite and certain varieties of ilmenite and hematite, are attracted by a weak magnetic field. Others, like chromite, garnet, glauconite, tourmaline, siderite, epidote, olivine, monozite and some varieties of ilmenite, hematite and amphiboles and pyroxenes, are weakly susceptible and respond only to the influence of a strong magnetic field. Still others, among them the common rock-forming minerals such as quartz, feldspars and calcite, are not influenced, even by a powerful magnetic field.

In response to magnetic influence, mineral grains may readily be segregated from other less susceptible minerals by bringing them into contact with or in proximity to a horseshoe magnet or the poles of an electromagnet. Only highly magnetic minerals will cling to a permanent magnet, but an electromagnet may be made powerful enough to attract and hold minerals of lower magnetic susceptibility; and by varying the strength of the magnetic field, components of different magnetic susceptibility may be segregated. Mineral grains so separated from a sand or disaggregated sandstone formation sample may provide a basis for identifying the stratum from which they come.

Dielectric Separation of Mineral Grains.—Minerals display resistance to passage of electrical discharge through them in varying degree. This property may provide a basis for concentration of certain mineral grains in disaggregated formation samples. The mineral grains are immersed in a liquid such as nitrobenzene, of known dielectric strength, and a voltage of from 300 to 400 volts imposed by immersing two closely spaced electrodes in the liquid. Mineral grains having a dielectric constant greater than that of the liquid will be attracted to a position between the electrodes

and may be removed for examination and mineralogic classification. Such minerals may be found to be a peculiar characteristic of the stratum from which they come.[64]

Electrostatic Separation of Mineral Grains.—Still another method of segregating certain minerals that may have diagnostic value in study of formation samples involves bringing the disaggregated grains of a formation sample into the field of influence of an ebonite rod that has been charged with static electricity by rubbing it with fur or flannel. Mineral grains to be tested by this method are placed in an electrically grounded copper pan and the charged rod brought in close proximity to them. Minerals that are nonconductive are positively charged and will attach themselves to the negatively charged ebonite rod, while others that are electrically conductive will be uninfluenced.[64]

Identification of Commonly Present Carbonate Minerals in Calcareous Formation Samples.—Different carbonate minerals are soluble in acids in varying degree, and this may provide a convenient basis for distinguishing between component members of a limestone formation. Thus, calcite is freely soluble in cold dilute hydrochloric acid, while dolomite and magnesite are less soluble. Magnesite is of higher density than dolomite and gravitational segregation provides a convenient means of distinguishing between them. This technic is useful in estimating the ratios of these minerals in calcareous samples which may have stratigraphic significance. Thus, the ratio of calcite to dolomite often shows diminishing values below an unconformity that might be difficult to recognize by other means.

In making segregations of carbonate minerals, the sample is first ground to pass an 80-mesh screen and about 2 cc. is placed in a 15-cc. graduated centrifuge tube with about 10 cc. of a solution of mercury iodide and potassium iodide (density 2.75). The material in the tube is shaken and centrifuged and such portion of the sample as remains afloat is poured off. This light "crop" is then recentrifuged in water and the volume of mineral accumulated is noted by reference to the graduations on the centrifuge tube. Dilute hydrochloric acid is added and the observed loss of volume of the mineral by solution in the acid is taken as the calcite content. Material that sank in the 2.75 density iodide solution is recentrifuged in an iodide solution of 3.05 density. The floating crop is poured off and recentrifuged in water, the volume of mineral noted and, after treatment with concentrated hydrochloric acid to which a little nitric acid has been added, the loss in volume of the mineral by solution is considered to be dolomite. To the heavy crop concentrated in the bottom of the centrifuge tube in the 3.05-density solution, water is added and the mineral again concentrated in the bottom of the tube by further centrifuging. The volume of mineral is noted, concentrated hydrochloric acid with a little nitric acid are added, and the loss in volume of the mineral by solution is regarded as the magnesite component. If anhydrite is present, it will be dissolved partly in the acid treatment of the medium-density fraction. In this case, the sulphate content of the solution must be analytically determined, the equivalent volume of anhydrite computed, and subtracted from the total volume loss to determine the volume of dolomite present.[10]

Concentration and Examination of Insoluble Residues in Calcareous Formation Samples.—Limestone formations are important reference horizons and reservoir rocks in many petroliferous regions. Often it is important to be able to recognize certain "markers" in such formations in tracing particular beds from well to well in a given field, or in making long-distance correlations between different localities. A useful technic, applicable only to calcareous formation samples, is one in which the carbonate minerals are dissolved in acid, leaving insoluble residues which, under the microscopic, may often be recognized as characteristic of the horizons from which they come. The residues that are left unchanged by the acid treatment are usually foraminifera, silicified fossils, grains of quartz, feldspars or other minerals of siliceous character.

A convenient method for dissolving calcareous material and concentrating the insoluble residue involves digestion of a pulverized sample in dilute hydrochloric acid prepared by diluting concentrated commercial HCl with an equal volume of water. One authority treats approximately 12 grams of the sample with 5 to 10 cc. of the dilute acid, until the active effervescence ceases, then adds 75 cc. more of the acid and allows it to stand until all effervescence ceases. Clay, inorganic precipitates and other fine material tending to remain afloat in the acid are decanted off and additional acid is applied until complete solution of all soluble material is assured. After complete digestion, the insoluble residue is washed several times on filter paper to eliminate all acid, soluble salts and finer particles and the coarser residues are dried and inspected under the binocular microscope to determine their character. A preponderance of one particular type of residue, or the presence of some unusual mineral or microfossil may be found to be characteristic of the stratigraphic horizon from which it comes.[28]

Concentration and Identification of Microfossils in Formation Samples

A field of scientific study, which has found wide application in geologic correlation in connection with petroleum exploration and oil-field development, involves microscopic identification of the microfossils that are frequently found in formation samples of sedimentary origin. Foraminifera and diatoms are abundant in rocks formed during certain periods of the earth's history, particularly in rocks of Cretaceous, Oligocene, Eocene and Miocene age. Marked variations in the skeleton forms of these microorganisms are noted, and often it will be found that a certain variety of microfossil is characteristic of a narrow formational interval over a wide area. Thus, the presence of a certain species may serve to identify a particular stratum wherever it is encountered within a given region or province. Foraminifera have been most used in this type of work, though some investigators have made effective use of diatoms.

Formation samples to be subjected to micropaleontological inspection are disaggregated, the finer material is washed through sieves or decanted, and the residue of sandy, coarser material which contains the microfossils may then be subjected to gravitational classification, dried and hand-sorted under the binocular microscope to find representative fossil specimens. Preliminary study will have established a series of reference specimens considered to be characteristic of different stratigraphic horizons, and these are permanently mounted on microscopic slides for comparative purposes.

Many years of research have established reference species for most of the important oil-producing regions of the United States, and identification of microfossils is now widely used as a means of geologic correlation. Most of the major oil companies support core-inspection laboratories equipped for this work, with skilled personnel in charge. Micropaleontological studies are depended upon for most of the geologic correlation work in some regions, and all cores taken in the course of drilling are regularly inspected to identify the species of microfossils that may be present.

Micropaleontology and petrography are sciences with which the petroleum engineer is expected to have only passing acquaintance. Study of formation samples by these methods is ordinarily entrusted to geologists who specialize in these fields. An extensive literature relating to them has been built up, which is inadequately reflected in the brief outline here presented, and the reader is referred to the selected bibliography at the end of this chapter for references that will bring more complete information.[13,18]

Magnetic Orientation of Cores

For many years, geologists and petroleum engineers have sought a dependable means of orienting cores taken in the course of well drilling, so that the stratification which they display may be used to determine the dip and strike of the formations penetrated. Such information is particularly helpful in determining the direction from the well in which the cores are taken, of crestal areas of structures encountered below unconformities or fault planes. In rotary drilling, primitive and costly methods of orienting the drill pipe and core barrel as they are withdrawn from the well have provided a possible solution of this problem, but these methods present inherent inaccuracies that cast considerable doubt on the usefulness of the data secured.

An important advance in the technic of core orientation was made with the development of a method which involves determination of the magnetic polarity of the core. The procedure, which is carried out in the laboratory with the aid of special equipment, is designed to determine the original orientation of the core as it existed in place in the earth, by observations on the residual magnetic polarity in the heavy minerals present.*

It has been found that many mineral crystals in igneous and plutonic rocks possess slight permanent magnetism, induced in them by the earth's magnetic field as the rocks cooled from the molten state. In later geologic history, as the older rocks are weathered and eroded away, the crystals composing them are freed and deposited in sedimentary formations and, as some of these crystals possess a weak magnetic polarity, there is a tendency for them to be deposited with their poles in the magnetic meridian. Although many such crystals are deposited in other positions, there is usually a sufficient majority oriented in the meridian to confer a distinct polarity to samples containing them. In addition to this orientation during the process of sedimentation, the mineral crystals are weakly magnetized by long standing in one position in the earth's magnetic field. To determine the original orientation, it is only necessary to provide an instrument sensitive enough to locate the magnetic north and south poles of the core.

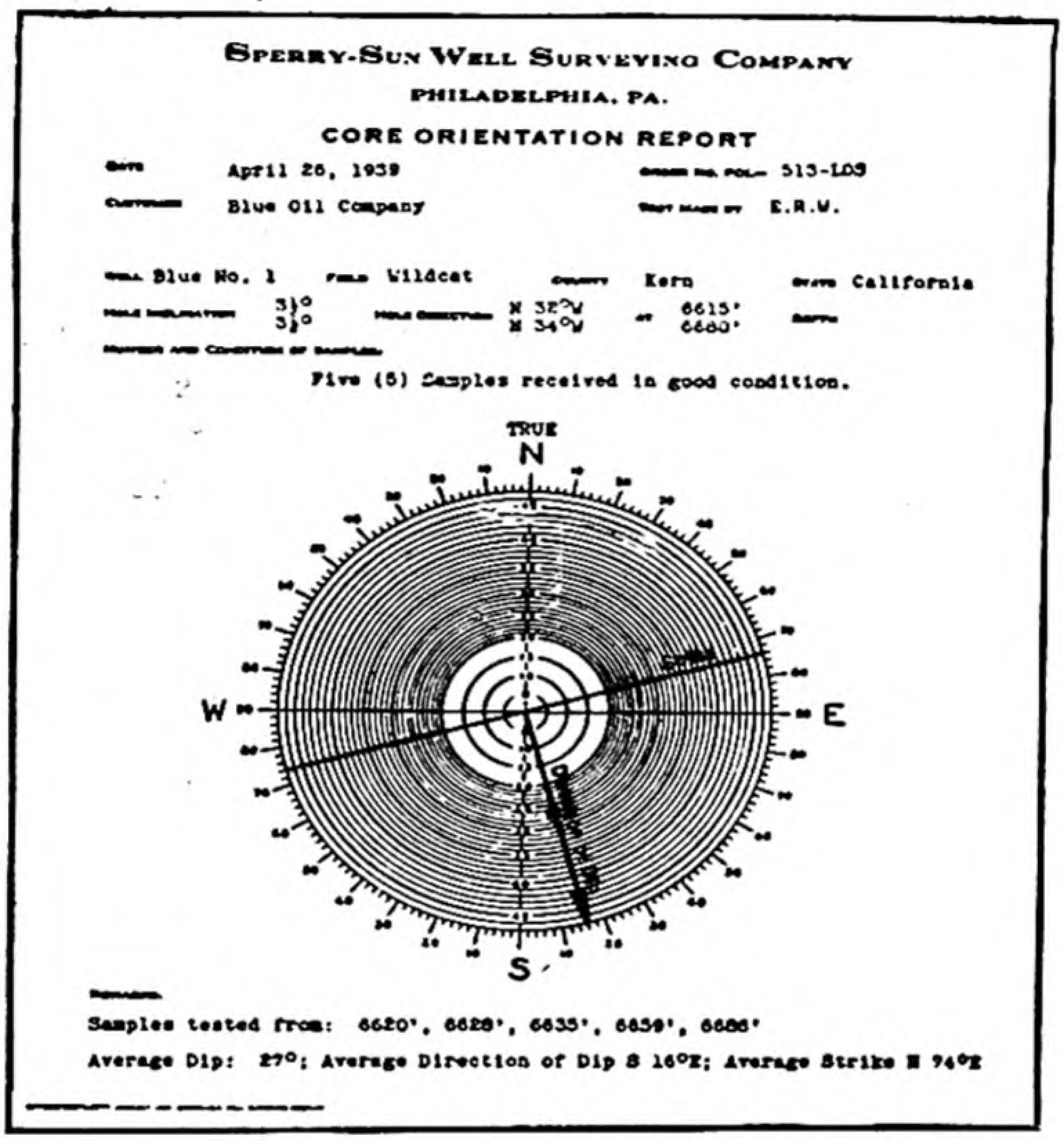
We must distinguish between the terms "polarity" and "magnetic susceptibility." Polarity is defined as that property of a mineral which enables it to acquire and retain magnetic polarity responsive to the earth's magnetic field. Susceptibility may be defined as that characteristic of a mineral which enables it to acquire magnetic properties which it does not retain after removal from the influences that have imposed a magnetic polarity. Many minerals are susceptible to magnetic forces but do not retain the polarity of the earth's field after they have been removed from it.[38]

Minerals may be classified in accordance with their magnetic properties into four groups: (1) highly magnetic minerals, such as magnetite and pyrrhotite; (2) moderately magnetic minerals, such as ilmenite, chromite and glauconite; (3) weakly magnetic minerals, such as monazite, staurolite and tourmaline; and (4) practically nonmagnetic minerals, such as quartz, feldspar, zircon and spinel. Unfortunately, some materials commonly present in core samples, such as limestone, dolomite, anhydrite and diatomite, have no magnetic properties. Of course, formation cores usually consist of a variety of different minerals having different magnetic properties, and the success of the magnetic method of core orientation will depend upon the amount of magnetic material present.

* Uren, L. C., Inspection and Analysis of Formation Samples: Orientation of Cores, Segregation and Identification of Mineral Components and Microfossils in Formation Samples, *Petroleum Engr.*, August, 1943, pp. 53–58.

In preparation for a magnetic polarity test, the core must be shaped by machine methods and it should therefore be of well-indurated material that will not disintegrate readily. The sides of the core are dressed to as nearly true cylindrical form as possible and the ends cut to smooth circular planes at right angles to the cylindrical axis. The upper end of the core is marked for identification and well-defined bedding planes that may be apparent in the core are marked clearly on the cylindrical surface to assist in later goniometric measurements.[90]

An apparatus suitable for use in determining the magnetic polarity of core samples has been developed and patented by members of the staff of the Standard Oil Co. of Calif. and the Sperry-Sun Well Surveying Corporation has been licensed to use this apparatus in commercial testing. The apparatus provides a means of supporting


SPERRY-SUN WELL SURVEYING COMPANY
PHILADELPHIA, PA.
CORE ORIENTATION REPORT
April 26, 1939 — 513-L03
Blue Oil Company — E.R.W.
Blue No. 1 — Wildcat — Kern — California
N 32°W 6615'
N 34°W 6660'
Five (5) Samples received in good condition.

Samples tested from: 6620', 6628', 6635', 6659', 6686'
Average Dip: 27°; Average Direction of Dip S 16°E; Average Strike N 74°E

(*Courtesy of Sperry-Sun Well Surveying Co.*)

FIG. 293.—Method of reporting result of magnetic core-orientation test.

and slowly rotating the prepared core in a horizontal position. Two magnets in astatic balance are supported near the core in a duralumin damping case, on a strand of copper-beryllium wire, so that they are free to turn in a vertical plane. The entire instrument is shielded from the earth's magnetic field by a cylindrical housing of soft steel. A small mirror, attached to the frame which supports the magnets, and turning with it, reflects a beam of light from an external source, so that it falls on a sheet of sensitized photographic paper mounted on the surface of a drum which rotates in synchronism with the core.[33]

As the core slowly revolves, the north end of the lowermost of the two magnets is attracted to the south pole of the core, and vice versa. A line is drawn on the cylindrical surface of the core, parallel with the longitudinal axis, indicating the side of the core that displays maximum attraction for the north pole of the lowermost magnet, and this is marked as the south pole of the specimen. It should be reproducible in repeated tests within a few degrees of arc. This is the side of the core that was toward the magnetic south as it existed in the earth. Suitable goniometric

observations, designed to measure the angle between a plane through the north and south poles of the specimen and the bedding planes, will determine the amount and direction of dip of the strata. A horizontal line at right angles to the dip angle, in the direction of the bedding planes, indicates the "strike" of the beds.

Rather than place dependence on tests with a single specimen, it is preferable to base computations on the average of tests made on several cores taken a few feet apart. The average result is conveniently indicated on a circular chart on which the direction of strike and dip are shown with respect to the points of the compass, while the amount of dip is indicated by reference to a series of concentric circles, each of which represents a certain degree of dip from the horizontal (see Fig. 293). When a core is taken in a well that is not vertical, suitable corrections must be applied to the apparent dip and strike to obtain the true values. An apparatus called a "deviation corrector" has been devised for mechanically solving this problem.[33]

Methods of Displaying Results of Core Inspection and Analyses

The foregoing pages have sketched the methods employed in selecting and preserving core samples and in conducting analytic tests thereon. The results of such tests are worthy of careful recording and thought should be given to the development of methods which will display the test data in readily assimilated form. Graphic methods are particularly appropriate and the engineer reporting results of field and laboratory studies of core samples will find it advantageous to present his data in this form as far as may be possible.

Sample Logs of Formations Penetrated in Coring.—In displaying the sequence and thickness of formations penetrated in the drilling of a well, or in coring operations incidental thereto, a graphic strip type of well log should be adopted (see pages 626–630). Judicious application of transparent water colors to graphic logs will add much to their appearance and assist in their interpretation. A novel method of displaying the character of material making up the formation penetrated by a well consists in preparing a graphic well log on which each stratum is represented by an actual sample of material taken from the formation samples of that horizon. For this purpose, two vertical and parallel india-ink lines are ruled, about 1 in. apart, on a sheet of heavy drawing paper or Bristol board. One-inch intervals are marked off along these lines, each 10 ft. of formational depth being represented by 1 in. on the paper. The vertical scale so established is labeled to correspond with 10-ft. intervals in the well. The position of each stratum from which samples are secured is determined on the graph by reference to the vertical scale. A thin solution of transparent, colorless mucilage or rubber cement is then evenly applied in turn to the space on the graph representing each stratum, and some of the pulverized formation sample from that particular horizon is sprinkled on with the fingers and left undisturbed until the adhesive hardens. Dilute, acid-washed, disaggregated samples are used for this purpose in order that the true character of the primary material will be apparent, and enough is applied so that the space between the india-ink guide lines is completely covered with as much as the adhesive is capable of retaining. Figure 294 presents a photograph of a sample log prepared in this way. On such a record the color, texture, size of grain and mineral content of the core material are readily apparent; and in a column at the right of the prepared log, the records of porosity, permeability, mineral determination and other tests that have been made may be recorded opposite the strata to which they relate. Such records may conveniently be maintained on 8½- by 11-in. or 8½- by 14-in. sheets and filed on edge in a suitable filing cabinet, with cotton sheeting between the individual mounts to prevent the mounted material from being rubbed off by abrasion.

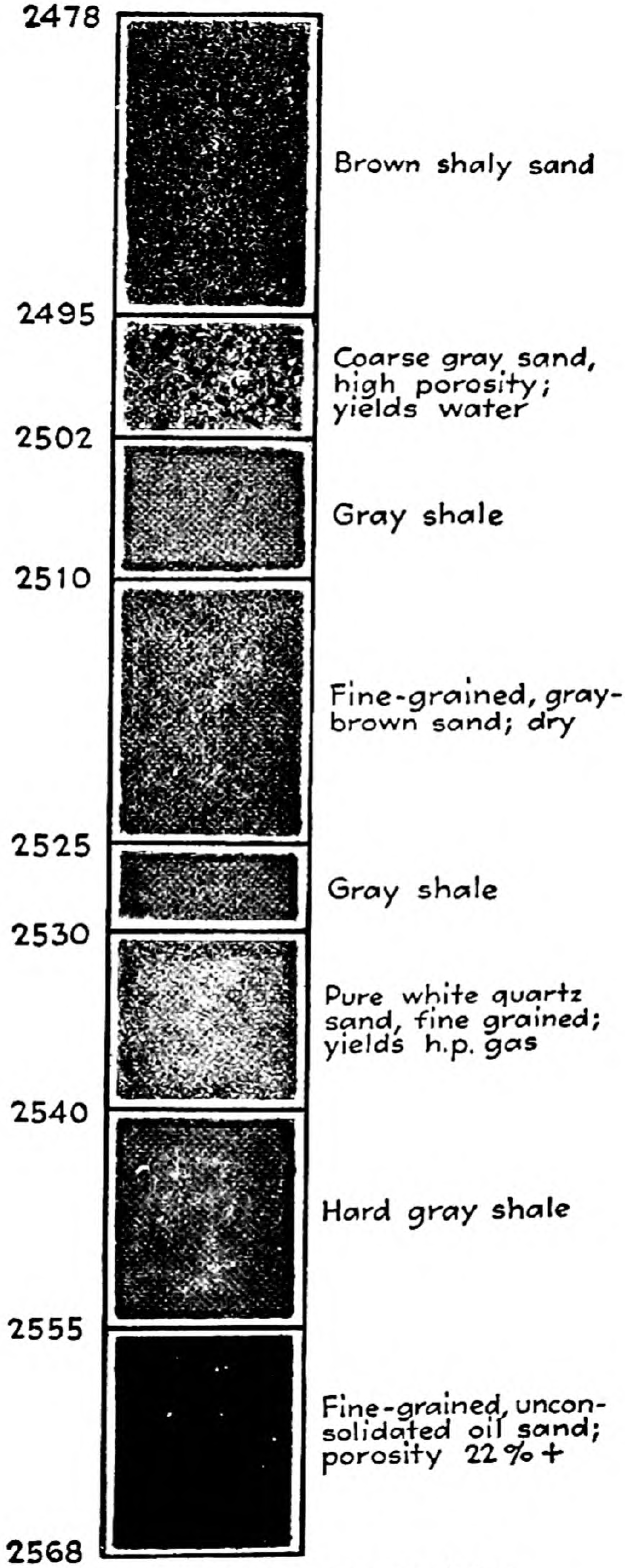


FIG. 294.—Portion of a sample log.

A more elaborate and cumbersome system of filing away a permanent record of all formation samples is to prepare a glass slide of each, on which a small quantity of the material is embedded in Canada balsam. Slides prepared in this way have the advantage that they may be conveniently examined under the microscope at any

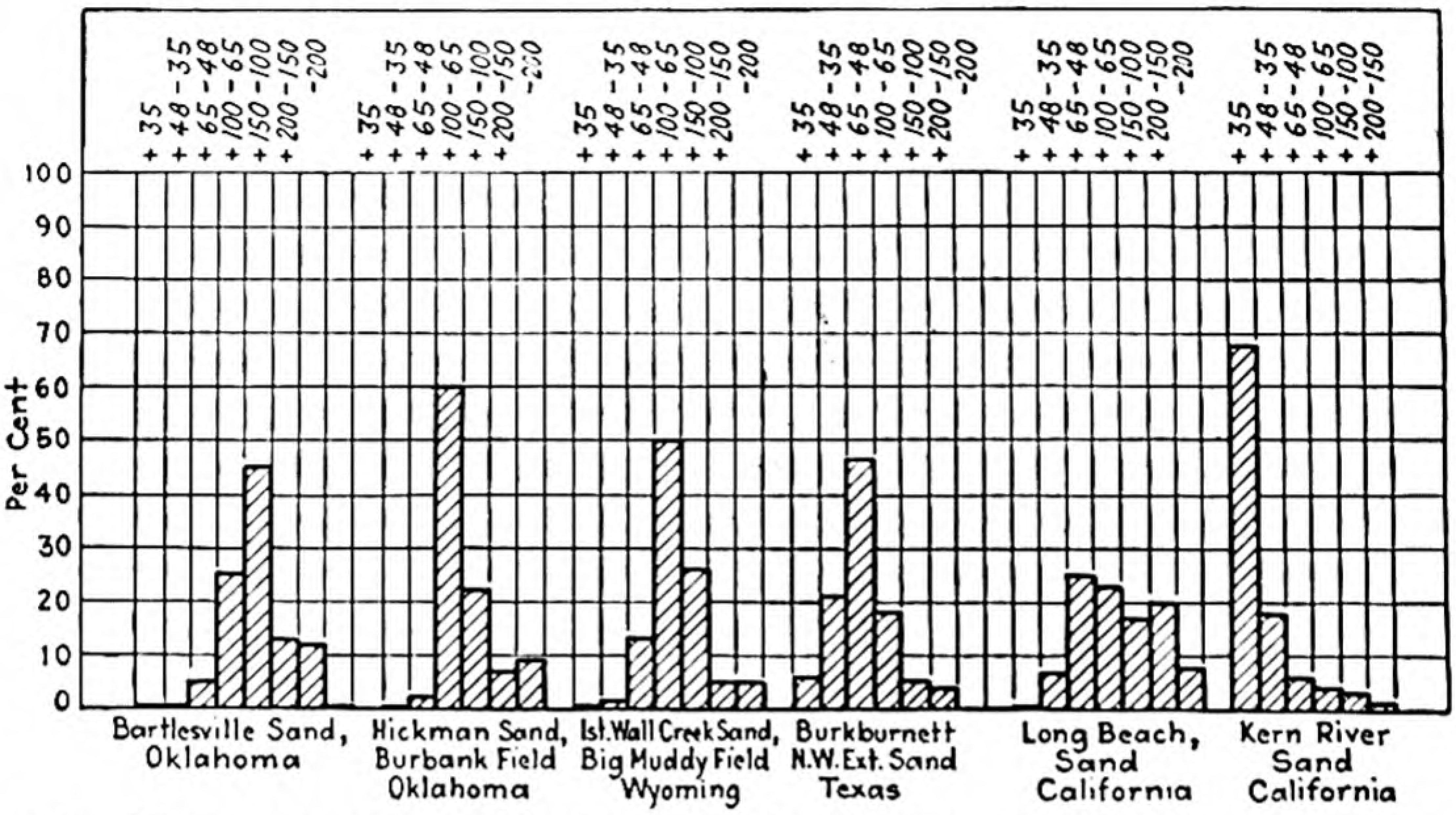


FIG. 295.—Histogram method of displaying results of screen analyses of formation samples.

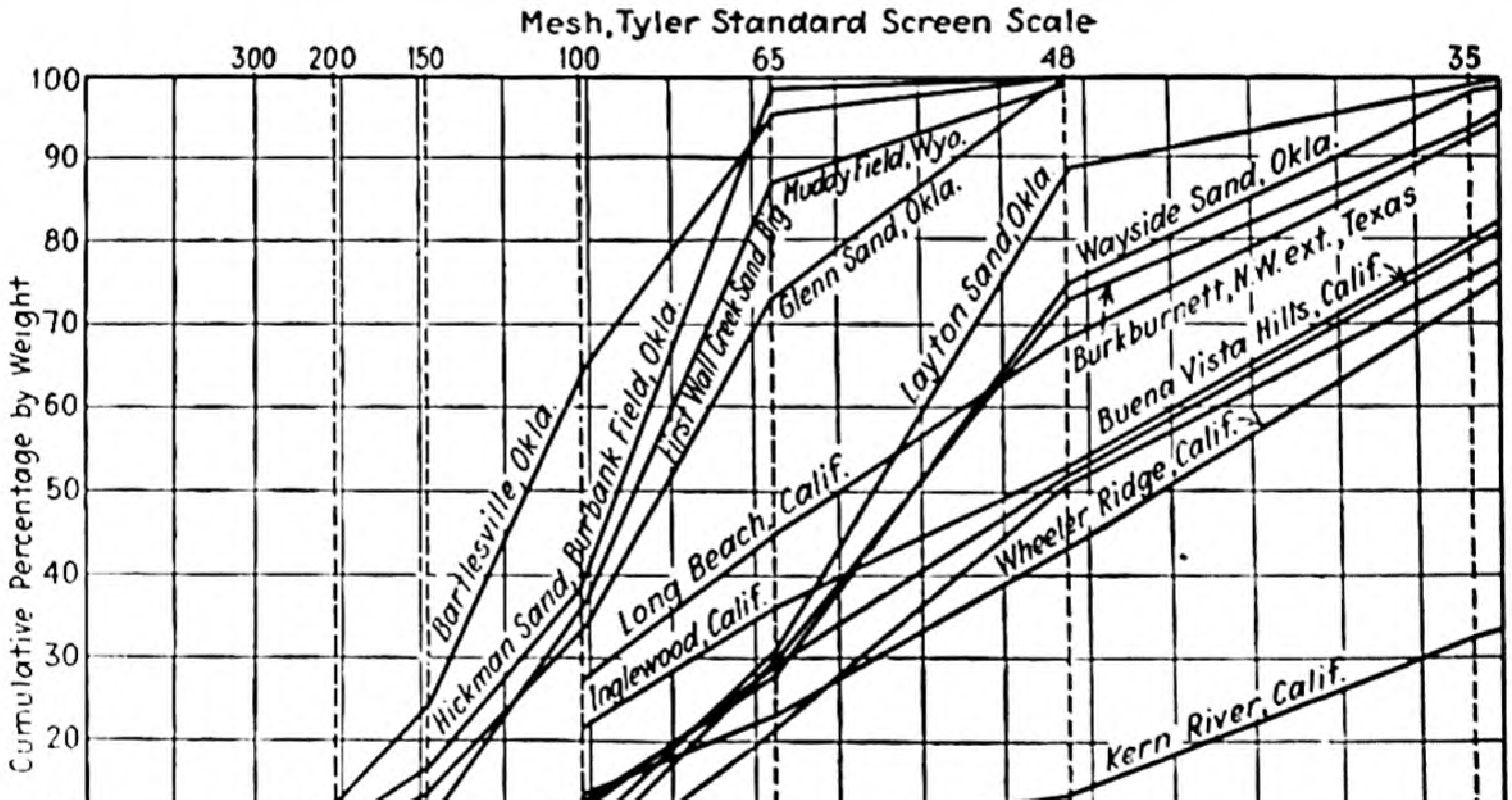


FIG. 296.—Cumulative percentage method of graphically displaying results of sizing tests.

future time, while the cardboard mounts do not lend themselves so readily to subsequent scientific inspection.

Graphic Methods of Presenting Results of Screen-sizing Tests.—Results of sand sizing tests, if presented in tabulated form, may be interpreted by the reader only with difficulty. Some graphic method of presentation is almost imperative with data of this character. A simple and easily understood method of presenting the

results of screen analyses called a "histogram" is illustrated in Fig. 295. A more useful method is that of plotting cumulative percentages against the sizes of screen openings, thus showing the percentages larger and smaller than each size of screen without the necessity of addition of component percentages. Figure 296 presents a

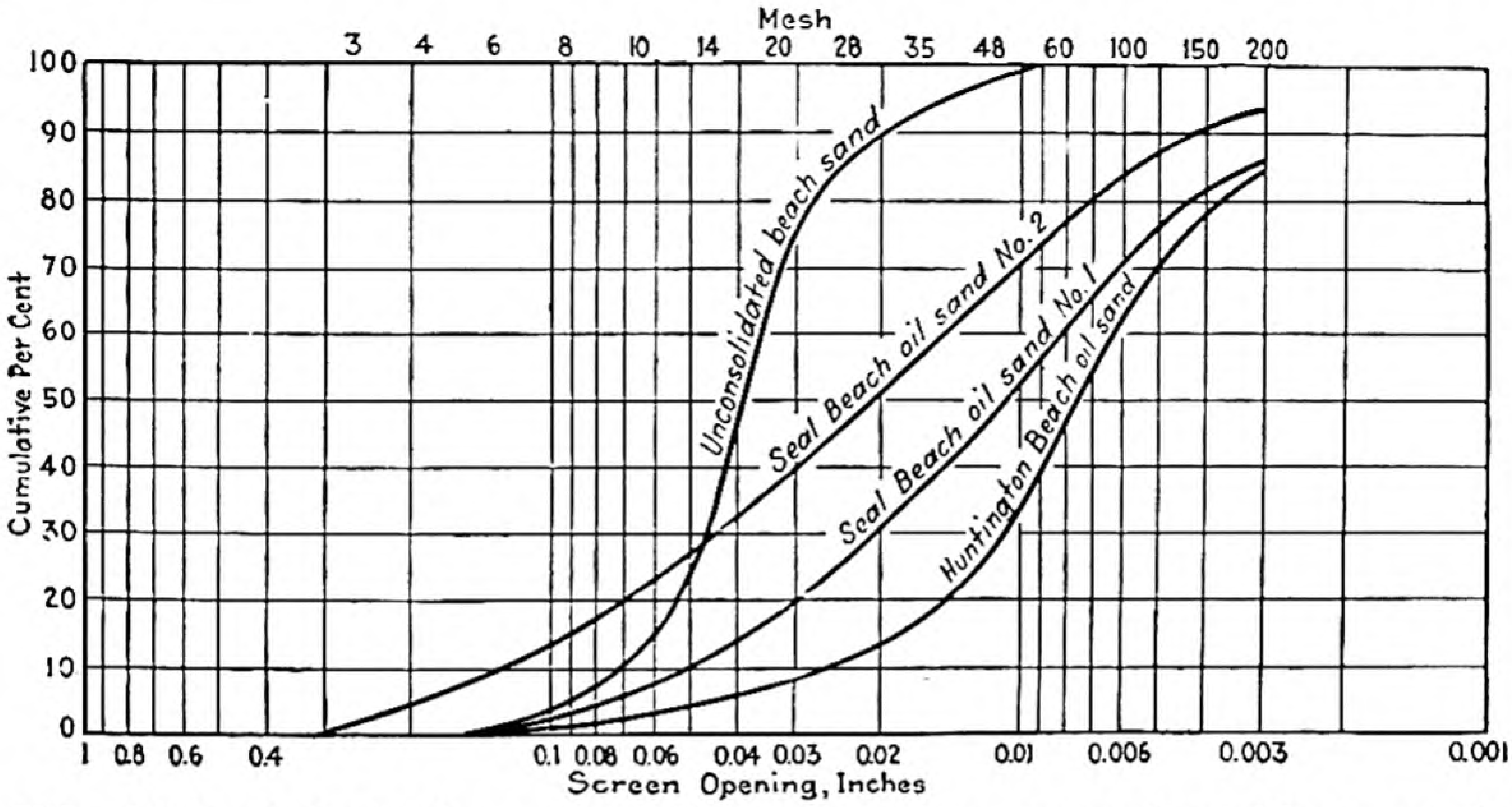
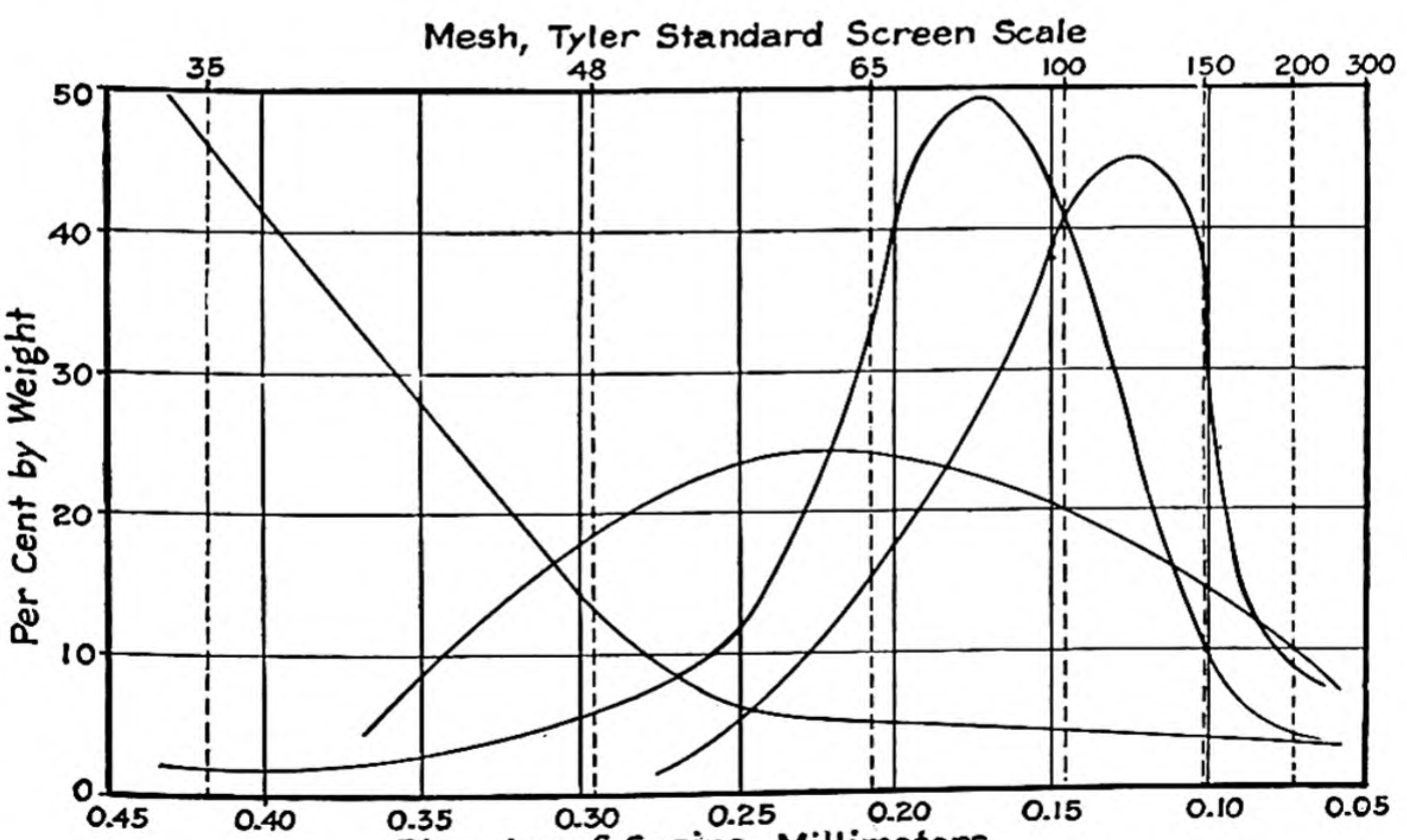


FIG. 297.—Method of plotting results of screen analyses on semilogarithmic coordinate paper.



(*From an article by the author in Petroleum Engineer, June, 1943.*)

FIG. 298.—Frequency distribution curves for typical oil sands.

series of cumulative percentage diagrams plotted on natural coordinates. Some engineers prefer to plot cumulative percentage diagrams of this character on semilogarithmic coordinate paper, as illustrated in Fig. 297. The logarithmic scale permits of displaying percentages of both large and small grain sizes on the same diagram to better advantage than is possible on natural coordinates.

Still another method of interpreting the results of a screen-sizing test in graphic form is the frequency distribution curve. This type of curve displays in graphic form the relative frequency with which particles of different sizes occur in the formation sample, reaching a peak at the point on the scale where the most abundant size of particle is found (see Fig. 298). The manner in which the different sizes are grouped on either side of this high point on the frequency curve is a significant characteristic of the sample for some purposes. Lack of symmetry of the curve about this peak is called "skewness," and a concentration of frequencies over a narrow range is called "kurtosis." These terms may be expressed quantitatively, with reference to the size-distribution curve, according to arbitrary conventions.* Thus,

$$\text{Skewness} = P_{50} - \tfrac{1}{2}(P_{10} + P_{90})$$

and

$$\text{Kurtosis} = \frac{P_{25} - P_{75}}{2(P_{10} - P_{90})}$$

In these expressions, P signifies the percentile point on the curve indicated by the subscript. Thus, P_{10} is the percentage by weight of that grain size at which 10 per cent of the grains are larger and 90 per cent smaller. Skewness may be either positive or negative. A negative value indicates that more of the material is fine grained than coarse grained.[64]

Graphic Method of Presenting Results of Inspection of Formation Samples.—Porosity and oil-saturation data may be conveniently presented in the form of profiles, plotting the percentages parallel with a horizontal scale opposite corresponding points on a graphic log arranged in depth sequence. Such a method of displaying the results of porosity and saturation tests shows at a glance the strata within which the greater part of the oil is confined and suggests the points at which packers and perforated tubing should be set to confine the flow of fluids from the reservoir sand. Comparatively barren strata are equally well displayed. Taken together, these two profiles indicate quantitatively the volume of oil in each component stratum of the productive formation, and for this reason it is desirable that they both be displayed on the same graph.

Figure 299 illustrates a type of record that graphically presents the results of porosity, permeability and fluid-content tests correlated with graphic driller's and electrical logs. Such a record provides a convenient basis for analyzing and interpreting the core-inspection data.

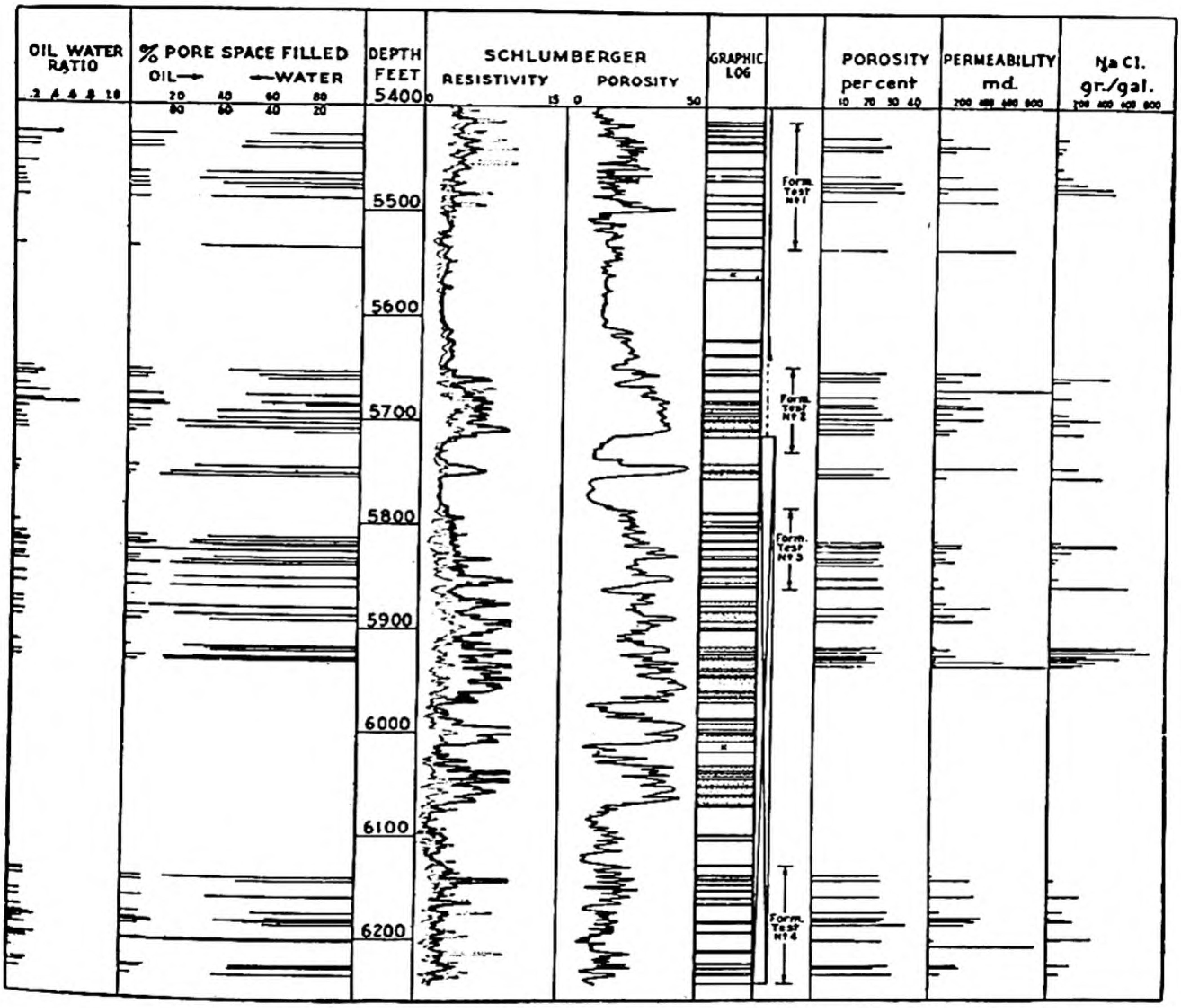
Computation and Graphic Presentation of Per-acre Oil Content of Land.—Knowing the porosity, oil saturation and thickness of each component stratum, the computation of oil content per acre is a simple matter. The formula used is as follows:

$$\text{Per-acre content in barrels} = \text{per cent porosity} \times \text{per cent oil saturation} \times \frac{43{,}560 \times \text{thickness in feet}}{5.6146}$$

The figure 43,560 is the number of square feet in 1 acre and 5.6146 represents the number of cubic feet in a barrel. Application of the formula may be simplified somewhat by using the constant 7,758.34 in lieu of the relation 43,560/5.6146. Values of oil content per acre are computed for each component stratum of the reservoir sand, and simple addition of these figures gives the total oil content per acre. It is often

* KELLEY, T. L., "Statistical Method," p. 77, The Macmillan Company, New York, 1923.

convenient to know the relative richness of different strata, and for this purpose the oil content per acre-foot may be computed for each productive stratum. This figure may be readily determined for each stratum in the computations of total oil content per acre, by merely segregating the product of the factors (per cent porosity × per cent saturation × 7,758.34) before multiplying by the thickness. Values of per acre-foot oil content may be conveniently displayed in graphic form by plotting values against an appropriate horizontal scale, opposite corresponding points on a graphic



(*After Pyle and Sherborne in Am. Inst. Min. Met. Eng. Trans.*[52])

FIG. 299.—Graphic method of displaying results of core analysis and correlating with electrical log of well.

log. The profile so developed may be conveniently arranged on the same graph as that used for the porosity and saturation profiles. Total oil content for component strata and the total oil content per acre may also be conveniently displayed opposite corresponding points on the graphic log. In this way, all essential porosity, saturation and oil-content data for a given well may be displayed in graphic form on a single page. If desired, two additional profiles showing water saturation in per cent and water content per acre may also be drawn. Use of appropriate tints to characterize the different profiles will permit of all being placed on one page without confusion in interpretation.[51]

ANALYSIS OF GROUND WATERS

Many of the petroleum engineer's problems are concerned with ground waters, and a knowledge of their chemical characteristics is often essential in the conduct of various field operations. As explained in Chap. XII the nature of the dissolved salts present in the ground waters varies markedly at different depths, and chemical analyses of the waters have provided a convenient means of correlating strata encountered in different wells. The salts present in ground waters may exert an important influence in determining the success of oil-well cementing operations, or they may have a bearing upon the rate of deterioration of well casing, tubing or other well or surface equipment with which they may come into contact. Water incursion into a producing well is regarded as a menace to continued production. Often it can be excluded if its source is known, and if the saline content of the waters encountered in different strata during the drilling of each well is recorded, their subsequent identification is facilitated. In some oil-producing regions it is found that the nature of the dissolved salts bears a certain relationship to the proximity of oil-bearing sands within the formation in which they occur and may be used to some extent as a basis for prediction or geologic surmise in petroleum exploration.

The importance of these applications in the work of the petroleum production engineer requires that he be familiar with the methods of making and interpreting water analyses, and he should have at his command in the field laboratory the necessary facilities and reagents for making water analyses.

Although many different substances may be present in ground waters, often in important amounts, the number of chemical elements and radicals in which one is normally interested in the applications suggested above can be reduced to comparatively few. These are the carbonates, bicarbonates, chlorides and sulphates of the strong alkalies, sodium and potassium, and of the alkaline earths, calcium and magnesium. A knowledge of the relative amounts of these substances will ordinarily be all that will be required in determining the chemical activity of a ground water, so that its probable reaction under any conditions may be predicted; or so that its true character may be determined for comparative purposes. In some fields it may be found that some less common or ordinarily less abundant substance, such as iron, strontium, barium, lithium, iodine, bromine or sulphur in the form of sulphide, is present in abnormal amounts in the ground waters of particular horizons. Space does not here permit of discussion of the routine of water analysis, and the interested reader is referred to standard works of reference on this subject.[78]

Methods of Reporting and Displaying the Results of Ground-water Analyses.—The results of water analyses are customarily reported in milligrams per liter, grains per gallon, or parts per million. If the amounts of the various elements and radicals have been determined in grains per gallon, as is the custom of many analysts, the equivalent in milligrams per liter (or parts per million) for each constituent can be determined by multiplying the figures representing grains per gallon by 17.12. Such

an analysis, giving merely a statement of the amounts of different substances contained in a given quantity of the sample, is of little value as an expression of its real chemical character. Usually a number of different substances are present, but a mere recital of their amounts would be of little value in determining their reacting value with any particular substance with which they might be brought into contact, or in making intelligent comparisons between different ground waters. For example, samples of the same water, diluted to varying degrees of concentration, would appear as essentially different waters if merely the absolute values of their saline constituents were compared. If, on the other hand, we express the amounts of the various constituents on a percentage basis, a more reliable means of comparison is afforded. This is essentially what is done in determining the "reactive capacity" of the various constituents.

The reactive value of an element or radical is the quotient obtained by dividing the actual weight of the substance present in solution by its atomic weight. We may conveniently arrive at an equivalent result by multiplying by the reciprocals of the atomic weights, these reciprocals being termed "reaction coefficients." The reaction coefficients of the elements and radicals commonly present in ground waters are given in Table XLIV, here classified according to the character of their ionic charges.*

TABLE XLIV.—REACTION COEFFICIENTS OF ACTIVE ELEMENTS AND RADICALS COMMONLY FOUND IN GROUND WATERS

Positive Radicals	Reaction Coefficients	Negative Radicals	Reaction Coefficients
Sodium (Na)	.0435	Sulphate (SO_4)	.0208
Potassium (K)	.0256	Chloride (Cl)	.0282
Calcium (Ca)	.0499	Nitrate (NO_3)	.0161
Magnesium (Mg)	.0822	Carbonate (CO_3)	.0333
		Bicarbonate (HCO_3)	.0164
		Sulphide (S)	.0624

Table XLV presents the results of a typical ground-water analysis and figures indicating the method of computing the reacting values.

The sum of the reacting values of the positive radicals computed for a ground-water analysis must necessarily equal (approximately) the sum of the negative reacting values. After the reacting values have been computed, their percentages are

TABLE XLV.—ILLUSTRATING METHOD OF COMPUTING REACTING VALUES

Radicals	Parts per Million		Reaction Coefficient		Reacting Values (Equivalent to Milligrams of Hydrogen)	
Sodium (Na)	1,003.2	×	.0435		43.64	
Calcium (Ca)	17.3	×	.0499	=	.86	
Magnesium (Mg)	8.7	×	.0822	=	.71	
						45.21
Sulphate (SO_4)	230.4	×	.0208	=	4.79	
Chloride (Cl)	54.5	×	.0282	=	1.54	
Carbonate (CO_3)	1,067.0	×	.0333	=	35.53	
Sulphur (S)	51.7	×	.0624	=	3.23	
						45.09
						90.30

* AMBROSE, A. W., Underground Conditions in Oil Fields, *U. S. Bur. Mines Bull.* 195, 1921. See particularly pp. 88–95.

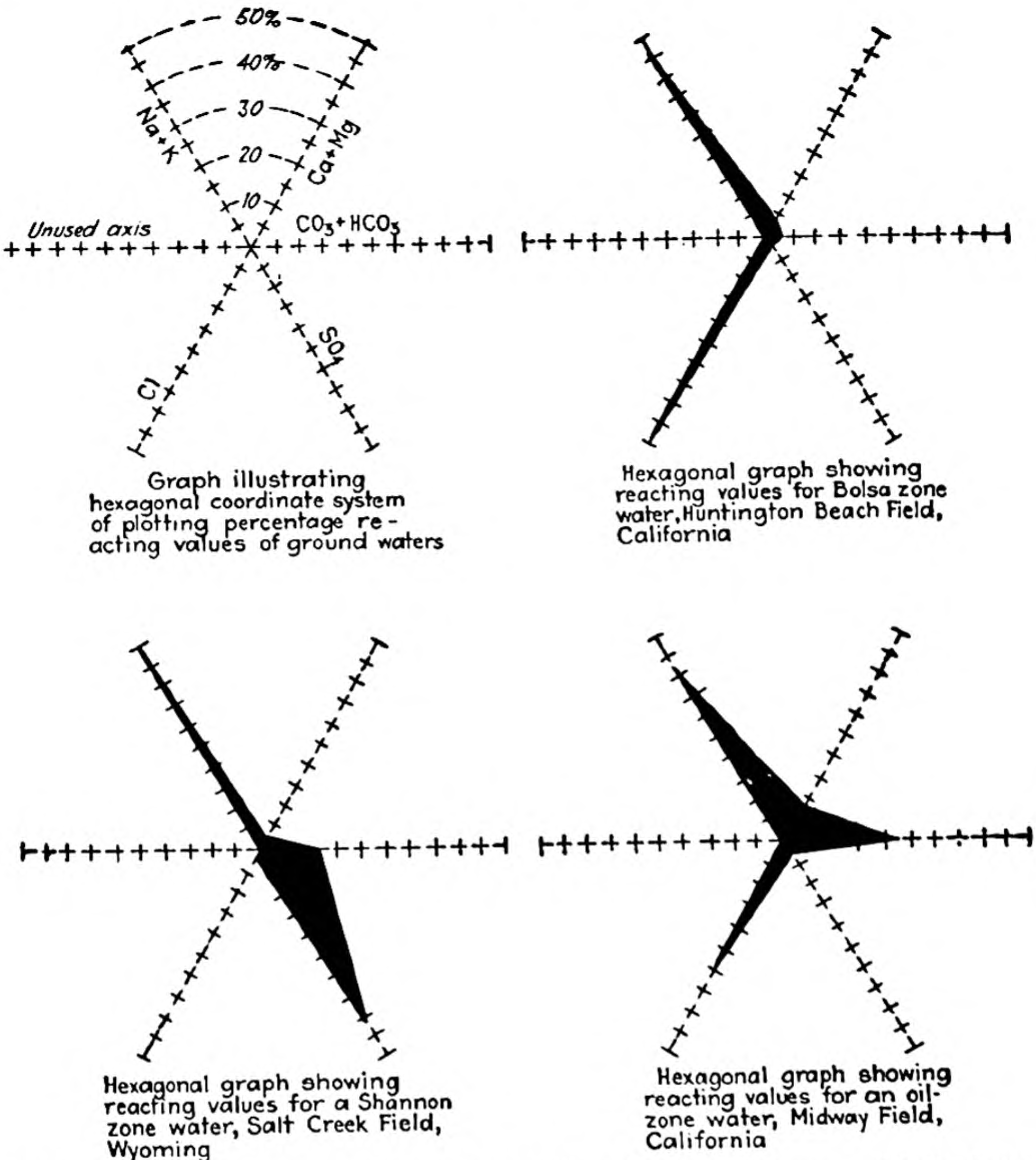


FIG. 300.—Hexagonal system of displaying results of water analyses. (Method suggested by F. G. Tickell.[79])

determined by dividing each by the total of all of the reacting values represented in the analysis. Table XLVI illustrates the method of computing the percentages for the analysis presented in Table XLV.

TABLE XLVI.—ILLUSTRATING METHOD OF COMPUTING PERCENTAGE REACTING VALUES

Radical	Reacting Values			Per Cent	
Sodium	43.64	90.3	=	48.3	
Calcium	.86	90.3	=	.9	
Magnesium	.71	90.3	=	.8	
					50
Sulphate	4.79	90.3	=	5.3	
Chloride	1.54	90.3	=	1.7	
Carbonate	35.53	90.3	=	39.4	
Sulphide	3.23	90.3	=	3.6	
					50

When a water analysis is expressed in percentage reacting values in the manner indicated in Table XLVI, all arbitrary units of measurement are dispensed with. Expressed in this form, the analysis becomes essentially a chemical formula, based entirely upon fundamental chemical laws. Expression of the results of analysis in percentage reacting values permits of ready and direct comparisons not possible by other means.

Graphical Representation of Water Analyses.—When water analyses are expressed in percentages of ionic constituents, as explained above, the results can be conveniently expressed in graphic form by plotting them on hexagonal coordinates. Connecting the points so plotted with straight lines produces a geometric figure, the form of which conveys in a graphic way a visual impression of the chemical nature of the water which the analysis represents. Figure 300 illustrates the method of constructing such graphs and presents several graphs of typical oil-field ground waters.[79]

The Stabler-Palmer System of Chemical Hydrology.—H. Stabler of the U. S. Geological Survey proposed, and Chase Palmer of the same organization later developed and applied, a system for the geochemical interpretation of water analyses that has since been widely used in studying oil-field ground waters. The method is one which seeks to express the analysis in terms of reactive power and chemical character rather than by ionic content.[75]

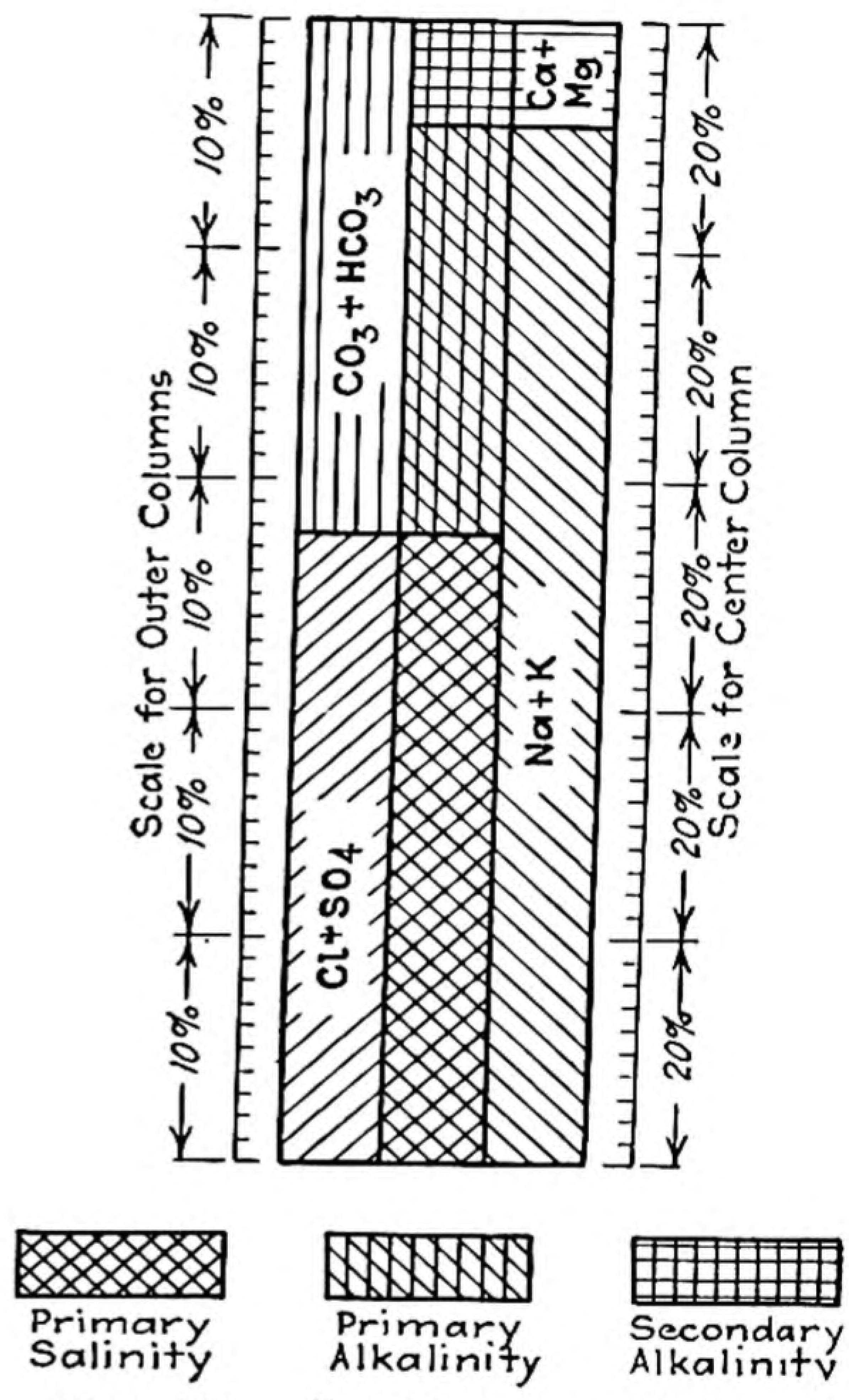


FIG. 301.—Graphic representation of character analysis of the upper edge water, Santa Fe Springs field, Calif.

The reactive power of a ground water is dependent upon the extent to which chemically active substances are present. These are of two general types: those which produce salinity and those which produce alkalinity. Both of these properties are induced in varying degree by different elements and radicals. The strong acids, combined with an equal reacting value of the primary bases, induce a property called "primary salinity"; combined with the alkaline earths they produce "secondary salinity." Primary alkalinity and secondary alkalinity are determined, respectively, by the excess of the alkalies or alkaline-earth bases over the reacting values of the strong acids. From the chemical analysis of a ground water the reactive values of the different components are computed, as explained above, and the total percentages of the different components causing primary and secondary alkalinity and salinity are determined. Table XLVII indicates the manner of computing the values representing primary and secondary alkalinity and salinity, once the percentage reacting values for all components have been determined. The water-analysis data presented in Tables XLV and XLVI are again used as a means of indicating the method of computation.

Graphic Method of Displaying Character Analyses.—Figure 301 illustrates a convenient method of graphically determining and displaying the saline and alkaline

characteristics of ground waters as provided in the Stabler-Palmer system. Here, by a system of hachuring applied to scaled areas representing the different ionic constituents, which will be readily understood on inspection of the illustration, the relative values of primary and secondary alkalinity and salinity are directly indicated.

TABLE XLVII.—SHOWING METHOD OF COMPUTING SALINITY AND ALKALINITY VALUES IN THE STABLER-PALMER SYSTEM

Primary salinity:

$(SO_4 + Cl)$ plus an equal value of Na and K $= (5.3 + 1.7) \times 2 = 14.00$.

Secondary salinity:

If $(SO_4 + Cl)$ is greater than $(Na + K)$, then $(SO_4 + Cl)$ plus an equal value of $(Ca + Mg) =$ . . . .*

Primary alkalinity:

Excess of $(Na + K)$ over $(SO_4 + Cl)$ plus an equal value of CO_3† . . . .
$= (48.30 - 7.00) \times 2 = 82.60$.

Secondary alkalinity:

Excess of $(Ca + Mg)$ over $(SO_4 + Cl)$ plus an equal value of CO_3† . . . . . .
$= (.8 + .9) \times 2 = 3.40$.

* $(SO_4 + Cl)$ not greater than $(Na + K)$ in this case.

† If sulphide or bicarbonate is recorded in the analysis, it is added to the CO_3 content.

WELL-SURVEYING INSTRUMENTS AND METHODS

Difficulties resulting from deviation of wells from the vertical have been explained in a previous section (see pages 330–331). Since crooked holes are the cause of so many difficulties, it is important that the operator have some reasonably accurate method of estimating to what extent the wells depart from the vertical and just where deflections occur in the course of each hole. A means must be provided for determining at any point the inclination of the axis of the well from the vertical, as well as the direction and distance, both vertically and horizontally, of any point in the well from the starting point at the surface. Need for information of this character has led to the development of a variety of well-surveying instruments, several of which are finding practical application in oil-field work. Space permits of brief descriptions of only a few of the more commonly used and characteristic types of well-surveying instruments. For more complete descriptions the reader is referred to the bibliography at the end of this chapter.

TYPES OF WELL-SURVEYING INSTRUMENTS

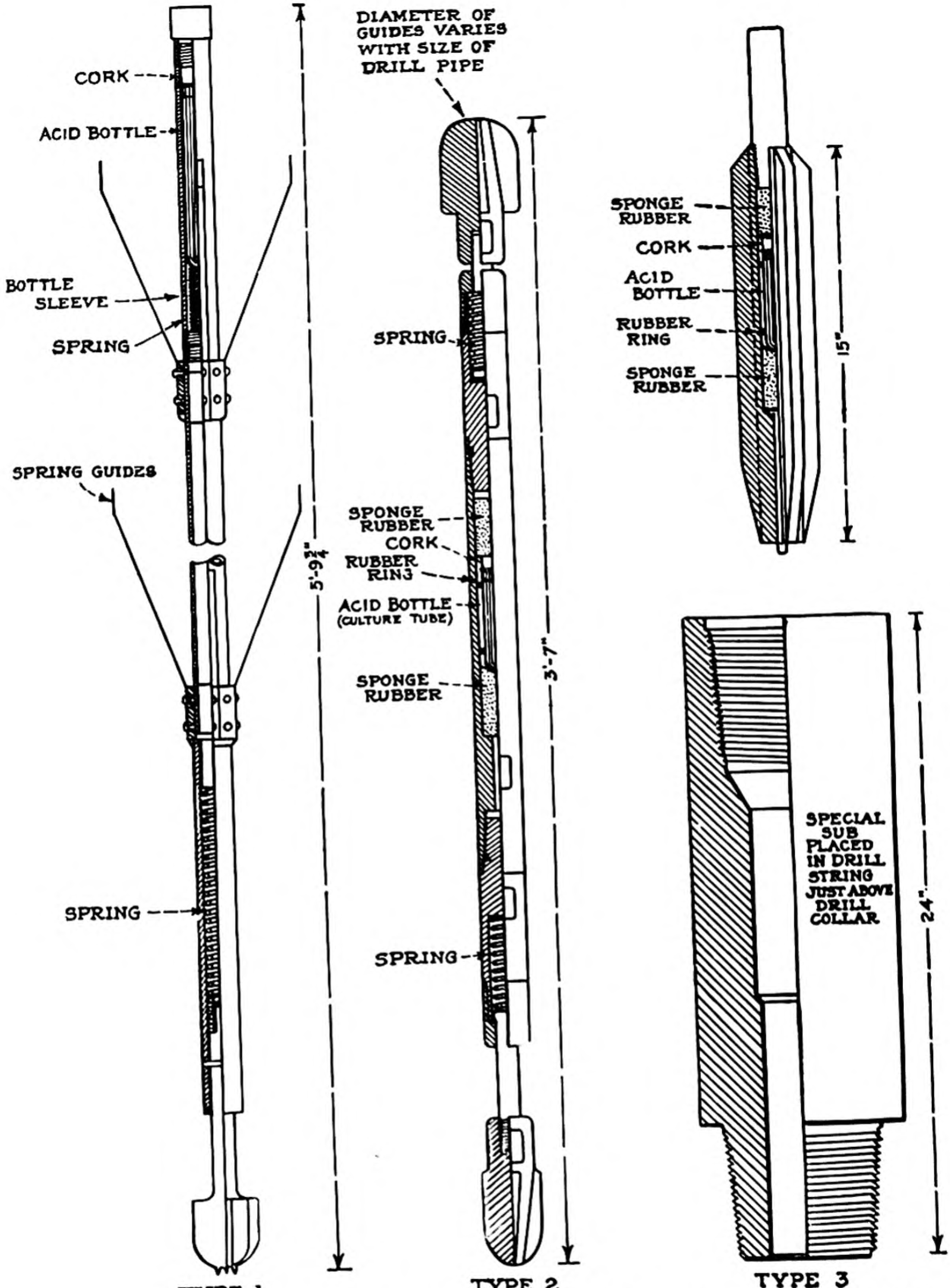
Well-surveying instruments are of two types: those recording vertical deviation only and those recording both the amount and direction of the deflection. The former are called "clinographs" and the latter "directional clinographs." Clinographs determine the amount of the deflection by recording either the position of a liquid surface or a gas bubble floating on a liquid surface, or the angle of inclination of a pendulum with respect to the axis of the well. Directional clinographs measure the direction

of the deflection either by a process of orienting the drill pipe or tubing on which the device is suspended in the well, or with the aid of various forms of compasses. The records are made either by photographic, chemical, electrical or mechanical means. Instruments designed to indicate only the amount of the deflection from the vertical are comparatively simple and easy to operate. Others, which show both the amount and direction of the deflection and which afford a means of determining the azimuth of any point in the well with respect to the starting point at the surface, are more complicated and require experienced and specially trained engineers for their operation as well as in the interpretation of the records resulting from their use. For this reason, most of the directional well surveying is done by individuals or companies specially equipped for this service and the work is done by specially trained engineers.

The charges for this service range from 6 to 12 cts. per foot of depth of hole surveyed, the price depending upon the type of instrument used, the location of the well and the equipment at the derrick for making the survey. Some of the instruments are also rented by the month or year or are sold outright to the oil or drilling companies for use by their own engineers. Most of the instruments are patented or have patents pending.

The Hydrofluoric Acid Bottle Inclinometer.—One of the simplest and most used methods of determining the amount of deviation of a well from the vertical involves the use of a little hydrofluoric acid in a glass bottle. If a cylindrical glass bottle partly filled with the acid is lowered to the point in the well at which the deflection measurement is desired and held at rest for 10 or 15 min., the level surface of the liquid will etch its position on the glass wall of the bottle, the axis of which is maintained in a position parallel to or coinciding with the axis of the well. When the bottle is subsequently withdrawn, the angle between the etched ellipse (marking the position of the acid surface while at rest in the well) and a circular cross section of the container is taken as a measure of the inclination of the well from the vertical. The etched ellipse on the inside surface of the glass bottle is sometimes a little "fuzzy," owing to movement of the fluid during its trip into and out of the well, but the position of the liquid while at rest in the test position is clearly apparent if allowed to stand long enough.[85]

Hydrofluoric acid is supplied by the manufacturers in wax bottles. In use, the concentrated acid is diluted with about an equal amount of water and placed in a cylindrical glass bottle about 1 or 2 in. in diameter. The bottle is placed in a steel container made secure against high external hydrostatic pressure. This is lowered into the well on the sand line normally provided for operating the bailer in a standard or combination rig; or it may be lowered through rotary drill pipe on a steel wire. One type of acid-bottle container is designed for use as a go-devil, being simply dropped into the rotary drill pipe at the surface and allowed to sink to bottom through the drilling fluid. Go-devils are preferably of such diameter that they may not fall freely through the mud fluid in the drill pipe. Sometimes they must be pumped down with the drilling fluid. They are often equipped with rubber supports or a plunger device to cushion the bottle and absorb the shock delivered when coming to rest on the upper end of the bit (see Fig. 302). They are generally used immediately before



(*After R. D. Copley in Am. Petroleum Inst. Production Bull.* 208.)

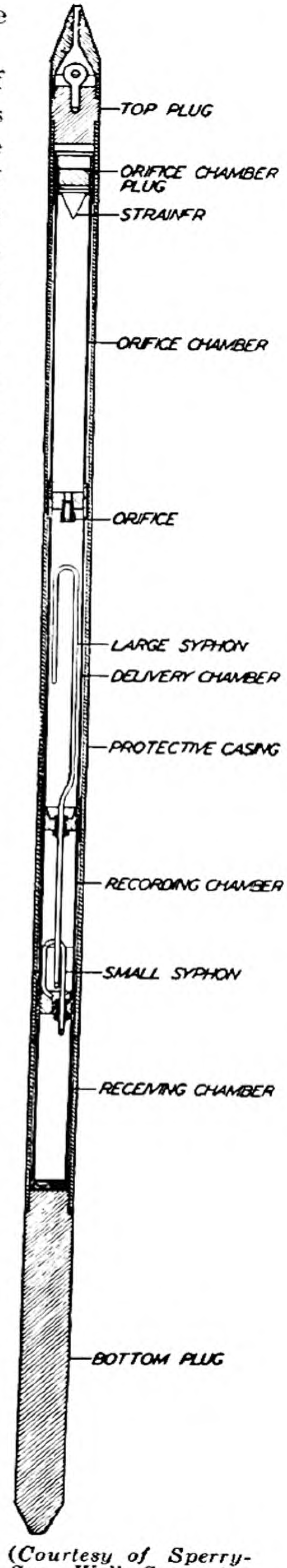
FIG. 302.—Types of acid-bottle inclinometers.

drawing out the stem to replace the bit so that they are in the well but a few hours at most.

The angle that the etched ellipse on the inside surface of the glass bottle makes with a plane at right angles to the axis may be read directly with the aid of a goniometer, or it may be computed by trigonometric methods from measurements of the inside diameter of the bottle and the distance between the high and low points of the etched line when projected on a plane parallel with the axis of the bottle. Another method involves the use of a strip of sensitized paper, which is wrapped tightly around the etched tube, starting at the high point of the etched line. The interior of the tube is then exposed to a light and the etched ellipse printed in the form of a curve on the sensitized paper. From this photographic record the amplitude or height to which the curve rises above its base is measured. This measurement, in conjunction with the diameter of the bottle, affords a means of computing the angle of deflection of the well. The meniscus formed by the acid in its contact with the glass wall of the bottle often makes somewhat uncertain the exact position of the acid surface while at rest in the well. This difficulty may be largely overcome by floating a little light lubricating oil on the surface of the acid, which tends to reduce the concavity of the meniscus.

Acid-bottle methods of measuring well deflections are probably not accurate within several degrees in many cases, and they are useful only in determining the amount and not the direction of deflection of the well. They have the advantage of simplicity, however, and have been widely used in well surveys in the American oil fields.

The Syfo Clinograph.—This instrument, like the acid bottle, operates on the principle of measuring the angle between a horizontal liquid surface and the axis of the well. Instead of acid a harmless dye solution is employed, leaving an impression of the level surface of the fluid on a paper chart so adjusted as to form a cylinder on the inside of the recording chamber. The dye solution remains in the recording chamber only a few seconds while making the record. The instrument comprises a brass cylinder which is divided into four compartments, one above another (see Fig. 303). The brass cylinder is supported in an outer protective casing closed at both ends with steel plugs. The uppermost of the four compartments contains a supply of ink or dye, which is permitted to flow slowly through an orifice into a second compartment. The latter is equipped with a siphon, so formed that when the ink reaches a certain level, it is suddenly siphoned into the third compartment or recording chamber. The walls of this compartment support the paper record chart, cylindrical in form, upon which the ink leaves an impression of the position of the level surface of the fluid while the device is at rest in the well. On rising to a certain level in the recording chamber, the ink is transferred by means of a second siphon into the lowermost compartment, in which it is stored until the instrument is withdrawn to

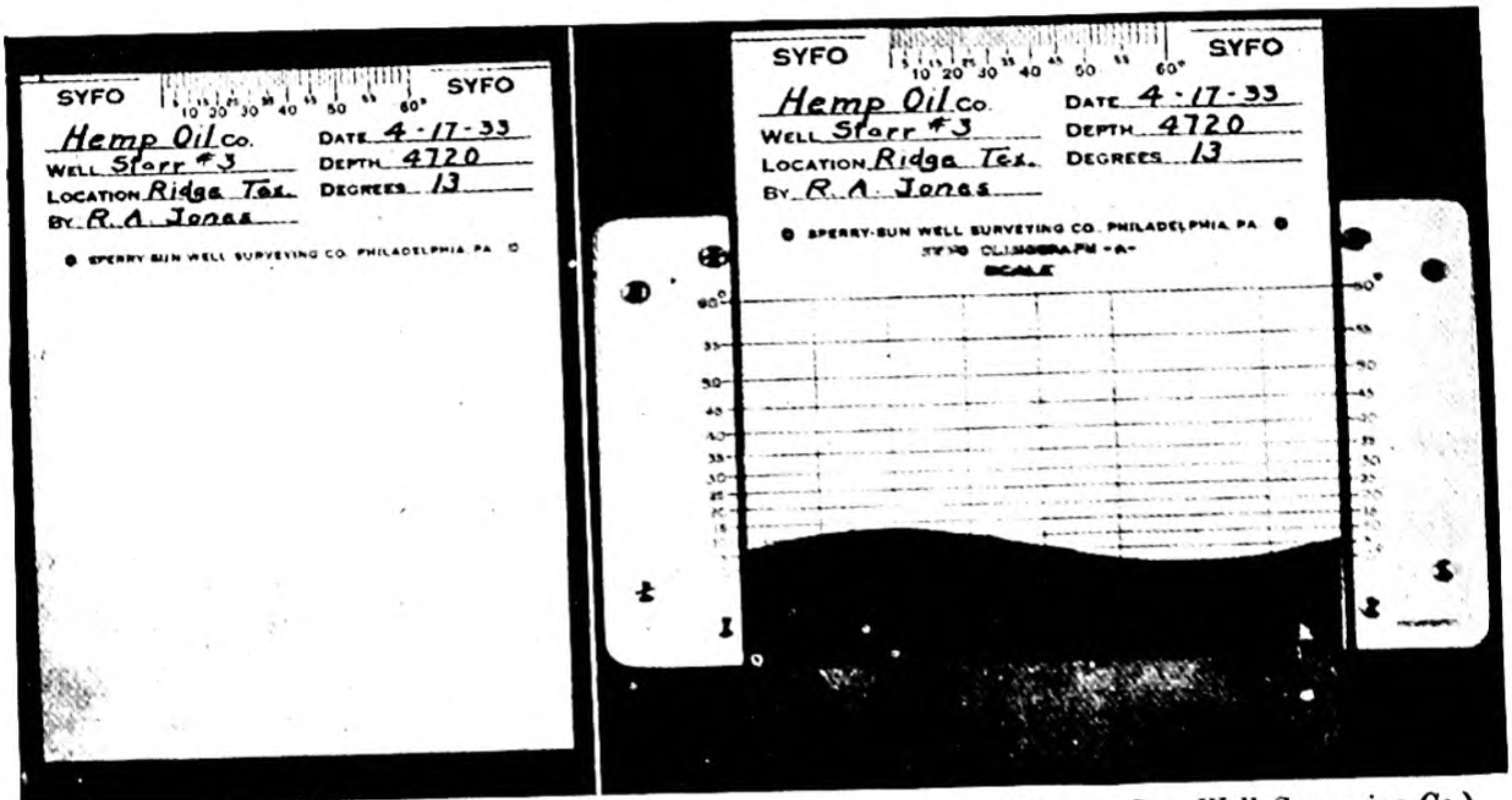


(Courtesy of Sperry-Sun Well Surveying Co.)

FIG. 303.—Vertical section through Syfo Clinograph.

the surface. The time that must elapse before the fluid enters the recording chamber is controlled by the size of the orifice between the first and second compartments, several different sizes of orifice disks being provided with the instrument. One is selected which gives sufficient time to assemble the instrument and lower it to the desired position in the well before the record is made. The instrument may either be used as a go-devil, or it may be lowered on the sand line or measuring line.

On removal from the instrument after withdrawing it to the surface, the paper cylinder, upon which the record has been made, is unrolled and measurements are made indicating the vertical distance between the high and low points on the ink-coated record (see Fig. 304). By reference to a scale printed on the top of the chart, this measured vertical distance may be quickly converted to degrees of inclination. As a further aid to rapid conversion, for angles up to 10 deg. the charts are ruled



(*Courtesy of Sperry-Sun Well Surveying Co.*)

Fig. 304.—Record made by the Syfo clinograph. Right: method of determining declination with the aid of a graduated reference scale.

horizontally, it being necessary only to count the number of horizontal lines between the high and low points on the ink-coated record, the number of scale divisions indicating directly the number of degrees declination.

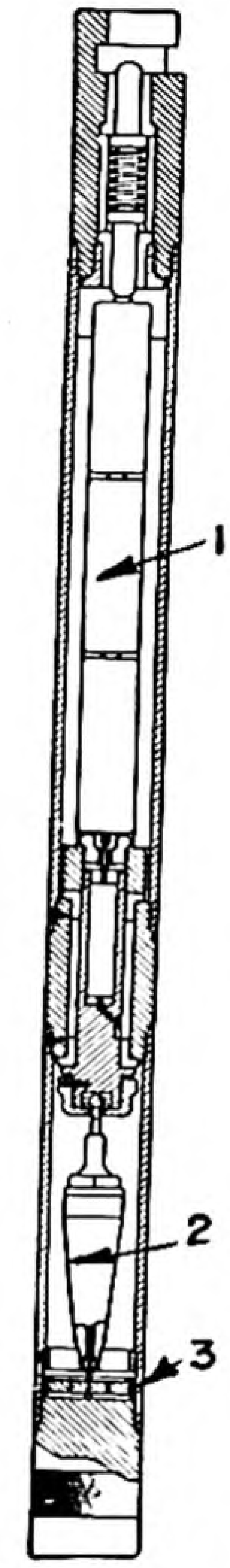
Syfo instruments can be obtained in three sizes: size AA with $1\frac{5}{16}$-in. outside diameter casing; size A with 1.9-in. outside diameter casing, and size B with 4.5-in. outside diameter casing. These instruments attain an accuracy of 1, $\frac{1}{2}$ and $\frac{1}{4}$ deg., respectively. The device is leased by the month or year.*

The E-C Inclinometer.—This device utilizes an electrochemical principle and requires no timing device. A chemically treated paper disk, bearing on its upper surface a series of concentric circles indicating the degrees of inclination, is continually in contact with the point of a free-swinging pendulum (see Fig. 305). A weak electric current from a series of dry-cell batteries flows continuously through the pendulum and disk. Only when the pendulum has come to complete rest for at least 1 min.,

* The Author is indebted to G. L. Kothny of the Sperry-Sun Well Surveying Company for the descriptions of the Syfo Clinograph and Surwel Clinograph, presented in this chapter.

is an easily readable record produced by electrochemical action on the chemically coated surface of the disk. No development or fixing process is necessary and the record is permanent. Three separately distinguishable records may be made on one disk at different depths in the well during one round trip of the instrument by allowing it to stand at rest for varying lengths of time. The circular marks formed on the disk increase in size with the resting time allowed.

The Hydril angle indicator is designed for use as a regular part of the drill-pipe column used in rotary drilling, being placed in a special sub carried in the drill pipe immediately above the drill collar. Circulation of drilling fluid is not restricted. A single record of declination of the hole may be made before starting drilling operations after replacing a bit, or just before drawing out the stem after completion of a period of drilling. The instrument indicates the amount of deflection of the well from the vertical at any point, by mechanically recording the position of a plumb bob which hangs from a universal joint in an oil bath. The plumb bob has an upward-extending arm surmounted by a serrated die crown. Screwed into the upper end of the instrument is a packing-gland assembly through which passes a piston rod attached to a sliding head within the body. On the underside of the head a concave metallic disk is removably attached. The lower spherical surface of the disk is marked off in concentric circles, each representing an increment of 2 deg. in declination. When in a vertical position, the longitudinal axis of the instrument passes through the center of the record disk and also that of the pendulum. Upon the instrument's being inclined, however, the pendulum maintains its vertical position and the record disk, being fixed in its relation with the axis of the instrument, assumes an inclined position.



(*Courtesy of Sperry-Sun Well Surveying Co.*)

FIG. 305.—Sectional view of *E-C* inclinometer. 1, dry-cell batteries; 2, pendulum; 3, recording disk.

The angle indicator is operated by the pressure of the circulating fluid, which depresses the piston and forces the record disk against the die crown, making an indentation which indicates the deflection of the pendulum. After making the impression on the record disk, the mechanism is automatically locked, so that no additional marks will be made. When the impression is made before drilling, a light metal disk-shaped "pressure cap" is attached to the upper end of the piston rod, partly restricting passage of the drilling fluid. When circulation starts, the piston is depressed until the record disk is penetrated by the die crown on the top of the pendulum arm. The pressure cup is then folded down over the piston head by the force of the fluid, leaving the passage for drilling fluid fully open. Drilling then proceeds in the usual manner and the instrument and record are not withdrawn until it is necessary to change the bit. When the reading is to be taken after drilling, the pressure cup is left off and, just before starting out of the hole, the kelly joint is disconnected and a metal ball dropped into the drill pipe. The kelly is then replaced and the ball pumped down until it reaches the instrument and depresses the piston, thus making the record. Momentary slowing of the pump shows when the ball strikes the plunger.

The Hydril angle indicator is very similar to the Elliott drift indicator, the principal difference being that in the latter instrument, the record disk is supported beneath the point of the pendulum and the pendulum itself is depressed to make the record.

Methods of Determining Direction of Deflection

The well-surveying devices described in the foregoing sections are designed to measure only the amount of deflection from the vertical and not the direction of declination. The amount of deflection, expressed in degrees, is all that is required in most cases, but where a complete survey of a well is necessary, a means must also be provided for determining the direction of declination. For this purpose we may make use of either of two methods. First, we may attach the instrument to a column of tubing or rotary drill pipe and orient the pipe into the well—a process which involves determination and recording of the extent to which the pipe supporting the instrument twists as it is lowered. Secondly, we may measure the direction of deflection by reference to a magnetic needle or a gyroscopic compass. Both of these methods are applied in various instruments used in well surveys. Both have their disadvantages, but either method is probably reasonably accurate when applied by a careful operator with instruments of suitable design.[82]

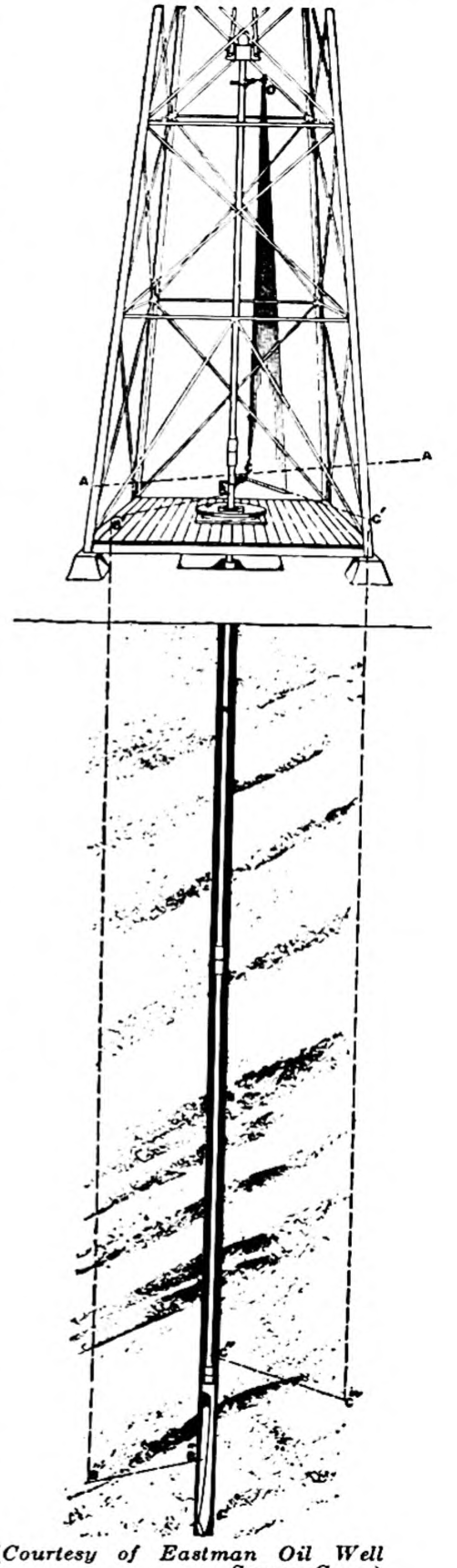
Orienting Drill Pipe or Tubing into a Well.—In determining the direction of deflection by orienting drill pipe or tubing supporting a deflection-recording instrument, the procedure varies somewhat in detail, but the objective is always the same. The sole purpose is to measure the amount of axial rotation of the pipe, relative to the points of the compass so that the position of the mechanism supported at the lower end, which measures the amount of deflection, can be determined at any time.

Several different methods of orienting drill pipe or tubing while it is being lowered into a well have been devised, so that the azimuth of a reference plane, through a surveying instrument mounted rigidly on its lower end, may be known at all times. The projected-vertical-plane method of orientation is one that has been widely used. In this method, suggested diagrammatically by Fig. 306, the surveying instrument (or well-deflection tool) is attached to the lower end of a stand of drill pipe, supported vertically above the well in the derrick and turned until the reference plane is in a conveniently checked position (*e.g.*, through diametrically opposite corners of the derrick). A sighting bar, supported by the lower of two orienting clamps (see Fig. 307) in a position parallel with the reference plane and at right angles to the axis of the pipe, assists in this adjustment. The upper clamp, supporting a telescope, is attached near the upper end of the stand of drill pipe and adjusted so that the vertical cross hair of the telescope is parallel with the vertical plane through the axis of the sighting bar. The telescope is then removed leaving the supporting clamp still attached in its fixed position on the pipe. The lower clamp and sighting bar are also removed and the pipe is then lowered into the well until the upper clamp is a short distance above the supporting slips in the rotary table. An additional stand of pipe is made up and screwed to the top of the column. The sighting bar is passed through the supporting clamp, the free clamp is attached near the upper end of the new stand of pipe, the telescope inserted in position on it, and adjusted so that its vertical cross hair again parallels the sighting bar. This procedure is repeated for each stand of pipe as it is coupled into the drill column, until the surveying instrument reaches the depth at which a record is to be made. The drill column is then turned until the sighting bar through the last-adjusted orienting clamp again assumes the original

azimuth selected for the reference plane. To relieve torque in the pipe, which may prevent the lower end of the column from responding freely to rotation at its upper end, the column is raised and lowered a few feet, and if the pipe turns a little, the sighting bar is again placed in the reference plane. This may be repeated until the sighting bar remains in the reference plane while the column is raised slightly and lowered.

A somewhat similar method of pipe orientation makes use of a pair of clamps attached, one at either end of each stand of pipe as it is coupled into the drill column in the derrick. Each clamp supports a small transit on a pinion parallel with the axis of the pipe (see Fig. 307). In lowering the pipe with the well-surveying instrument attached to its lower end, the pipe is turned until the cross hairs of a transit supported by a clamp near its upper end bear on a distant reference point that is visible also from the derrick floor. The transit is removed from the supporting clamp and the drill pipe is lowered into the well until the clamp at its upper end is but a short distance above the table slips. As the pipe is lowered, it usually turns slightly, one way or the other. The number of degrees of arc through which it has turned may be determined by again placing the transit in its position on the clamp—now near the derrick floor—and turning the transit until its cross hairs again bear on the distant reference point, observing the number of degrees turned off, right or left, on the alidade of the transit. This is repeated for each stand of pipe added to the drill column, keeping a record showing the algebraic summation of angles of rotation; that is, the angle of rotation for each stand is added algebraically to the sum of the prior angles of rotation. The position of the reference plane of the surveying instrument is thus known for each stand of drill pipe as it is lowered through the well.

The Autophoto orienting device, developed by the Eastman Well Surveying Company, is used in conjunction with the projected vertical plane method, but the number of degrees of arc through which the drill column turns as each stand is lowered is recorded photographically after the transit on the supporting orienting clamp has been again focused on the reference point. The photographs, made on a strip of sensitized film, provide a record from which the position of the reference plane of the surveying instrument can be determined for each stand of drill pipe lowered into the well. With this device, orientation of a column of pipe becomes

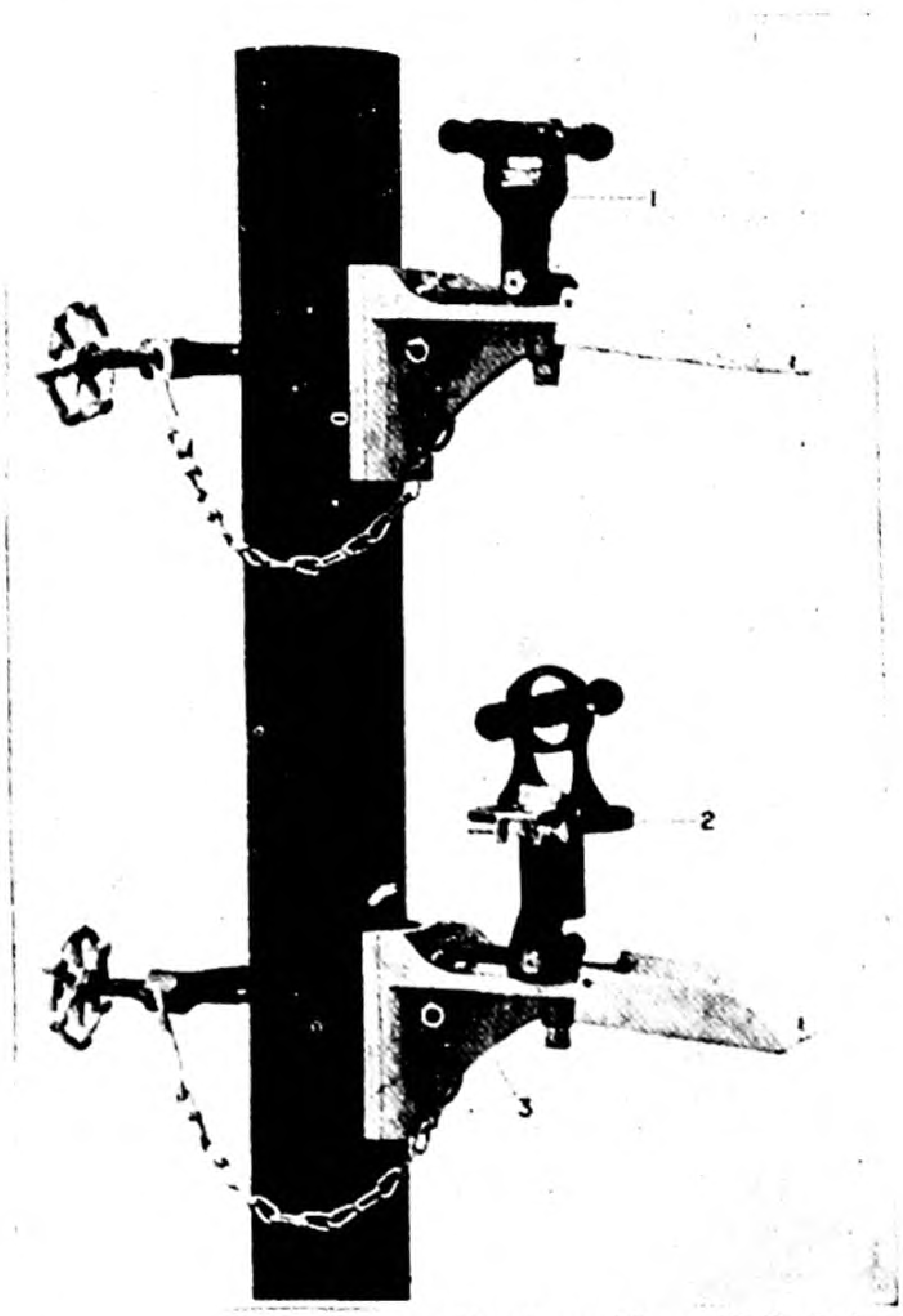


(Courtesy of Eastman Oil Well Survey Corp.)

FIG. 306.—Projected-vertical-plane method of orienting a surveying instrument or deflecting tool on drill pipe or tubing.

entirely mechanical. No computations are necessary; each angular measurement recorded is the algebraic summation of angular rotations from the original azimuth of the reference plane of the instrument.

There has been considerable discussion among engineers engaged in well surveying concerning the reliability of surveys based on the practice of orienting the drill pipe. Some claim that a column of pipe is twisted on lowering it into a crooked hole where there is considerable wall friction, with the result that there is no relation between the direction of a radial plane through a certain point on its circumference at a depth of several thousand feet and the direction that this plane assumed at the surface. It



(*Courtesy of Lane-Wells Co.*)

FIG. 307.—Clamps and telescopes for orienting drill pipe.

seems reasonable to expect that any turning of the pipe, as it enters the well, will develop torque in the pipe, which will be partly offset by wall friction, with the result that the computed position of the reference plane through the surveying instrument in the well, based on surface observations, may not correspond with its actual position. This view is opposed by some engineers who believe that whatever torque is given the drill pipe at the surface will be transmitted in equal amount to the bottom, thus preserving the orientation of the instrument. They point to numerous records where by repeated tests in the same well, utilizing this method, the records closely check. This is not always true, however, for there are other instances where holes surveyed by different engineers, using different devices, have varied widely in the reported direction of deflection. One engineer finds that about four out of six measurements check where the direction of deflection is determined by orienting drill pipe;

but, as he points out, it may be that the same errors are repeated in each test and that there is no assurance that the average reading is correct. However, some of the most active and successful engineers engaged in oil-well surveying use this method.

Use of the Magnetic Compass in Orienting Well Surveys.—A number of well-surveying instruments make use of various forms of magnetic compasses as a means of recording the direction of deflection of a well. The magnetic compass always points to the magnetic north, irrespective of the orientation of its supporting mechanism, unless disturbed by local magnetic irregularities. Consequently any instrument which combines means of securing a record of deflection of a well from the vertical with a record of the horizontal angle of deflection of the axis from an assumed reference line—such as a north-and-south line—affords a means of completely mapping its course. The magnetic needle provides a simple and direct record of the direction of deflection, providing the needle always points in the same direction while in the well. Many engineers believe that it does not. It is well known that drilling tools and drill pipe often become highly magnetized in normal use. Oil-well casings are often highly magnetic. Bodies of magnetic minerals in the formations penetrated may also cause local disturbance of the magnetic field. Many believe that these magnetic irregularities would have sufficient influence on a compass needle lowered in a well to make the compass unreliable as a direction finder.

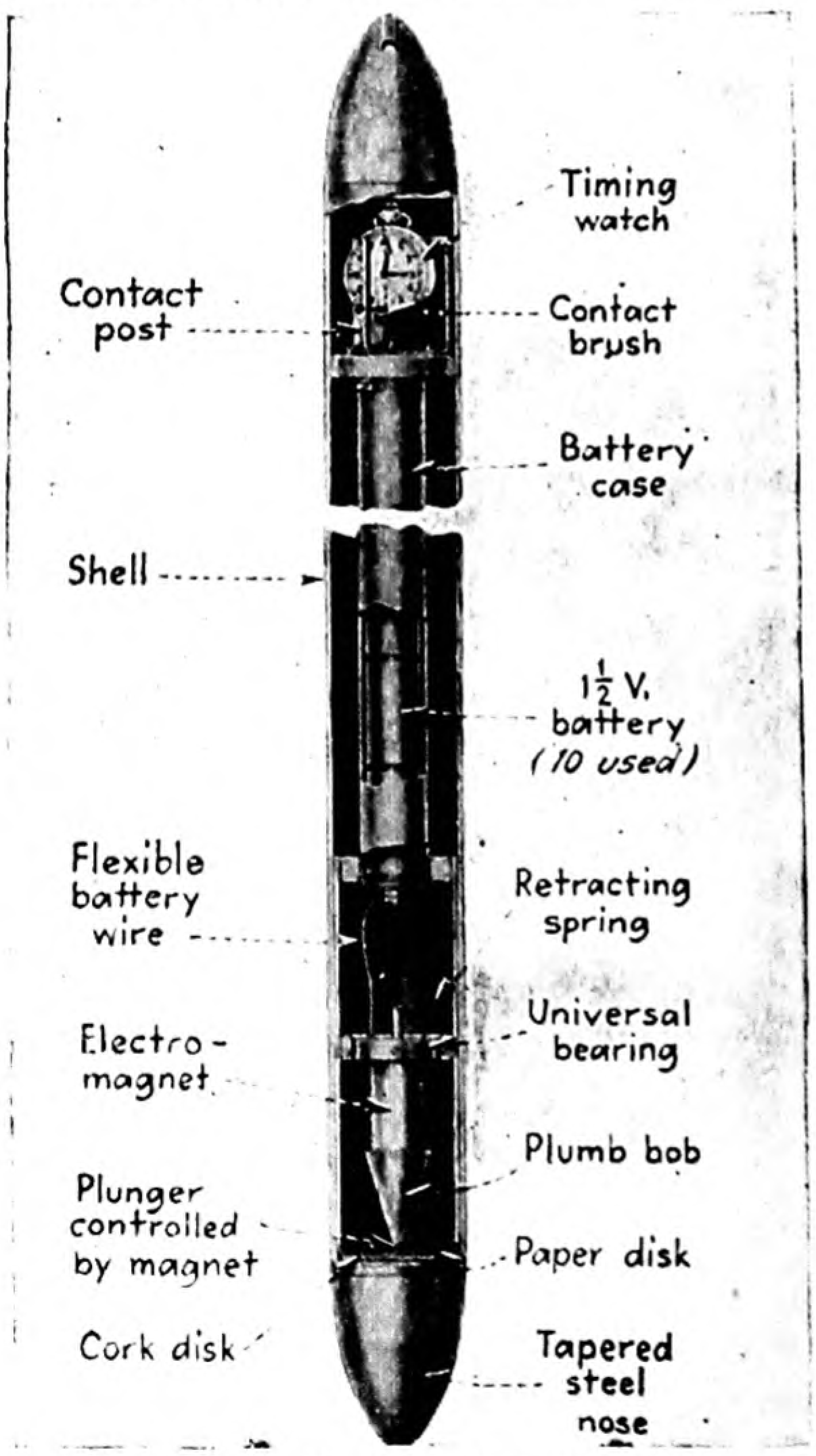
It is generally agreed that a compass needle is not dependable when operated in a steel or iron casing which tends to shield it from the earth's magnetic field, and where used in well-surveying instruments they are accurate only in open hole or in tubing made of nonmagnetic material.

Use of Gyroscopic Compass as a Means of Orienting Well Surveys.—A gyroscope comprises a rotating wheel supported in such a way that it is free to move about three different axes. When caused to rotate rapidly about one of these axes, it is capable of maintaining its original plane of rotation in space, irrespective of changes in inclination of the supporting mechanism. This property of the gyroscope provides a useful means of indicating the direction of the reference plane of a well-surveying instrument, for if started rotating, say, in a north-and-south plane, the device will continue to maintain itself in this plane as long as rotation continues. A suitable reference marker and a means of recording the position of the gyroscope in its relation with that of a device for measuring the amount of deflection—such as a pendulum—will indicate the direction of the deflection quite independently of the amount of torsion in the supporting pipe or of magnetic influences that may be operative. Among the problems in adapting the gyroscope to this type of work has been the difficulty of making a dependable one small enough for use in a device that can be lowered into an oil well and of providing for the necessarily rapid rotation of the gyroscope wheel. However, the Sperry Gyroscope Company, after several years of research work, has perfected a small gyroscopic directional indicator that has been found well adapted to oil-well service and is embodied in the Surwel Clinograph which is to be described in a later section.

The Driftmeter.—The Driftmeter utilizes a free-swinging, rigid-arm type of pendulum, suspended on universal bearings above a paper disk, the center of which marks zero deflection (see Fig. 308). Concentric circles about this point mark deflection increments of 1 deg. The instrument is equipped with twelve 1½-volt flashlight dry batteries and a clock which can be set to close an electrical circuit after any desired number of minutes have elapsed—a time sufficient to allow for lowering the instrument to the point in the well where the record is to be made. It may be lowered on the sand line of the cable-tool or combination rig, or on a special measuring line. When the circuit is completed, a small electromagnet, actuated by the dry batteries, raises the record chart, causing a perforating needle on the point of the pendulum to

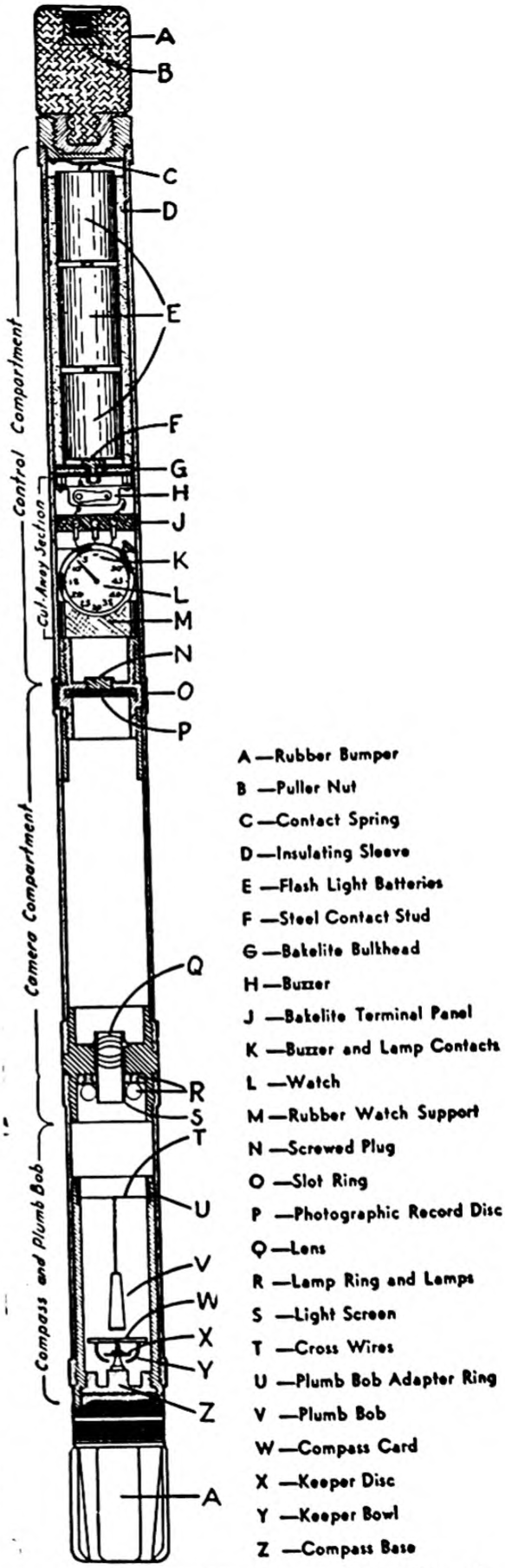
be thrust against the paper disk, thus recording the amount of deflection. For indicating the direction of inclination, a horizontally swinging compass is provided, the compass being automatically clamped in its rest position at the time the record is made by the same mechanism that raises the record chart. The direction of inclination is in the direction of a line drawn through the center of the chart and the needle prick marking the position of the point of the pendulum. The bearing of this line may be determined by reference to the position of the compass needle, since the position of the chart bears a fixed relation to that of the magnetic north point of the compass.

Single-shot Photo-record Magnetic Directional Clinograph.—A commonly used well-surveying instrument is one designed to obtain a single record of the inclination



(*Courtesy of Driftmeter, Inc.*)

FIG. 308.—Sectional view of the Driftmeter.

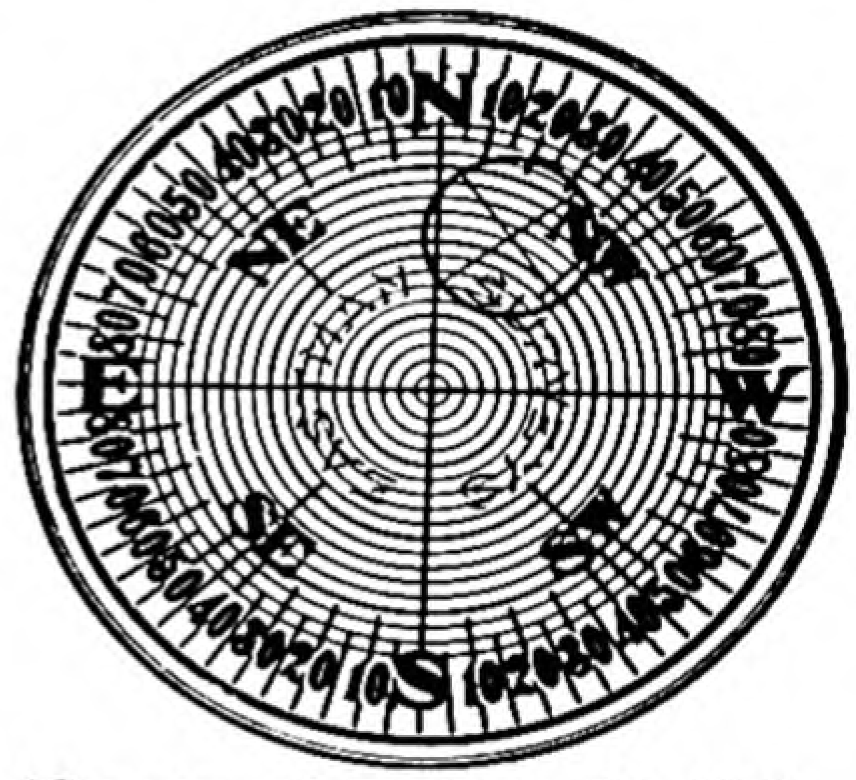


(*Courtesy of Alexander Anderson.*)

FIG. 309.—Single-shot photo-record magnetic directional clinograph.

and direction of deflection of a well at any point in its course to which it may be quickly lowered on a sand line. The time required is but little more than is necessary to lower and raise a bailer into and out of the well. It employs a plumb bob to indicate the amount of deflection and a magnetic compass to indicate the direction of deflection. Because of this latter feature, it is dependable only in uncased holes. Although the instrument makes only one record each time it is run into and out of the well, a complete survey of a well may be made by applying it repeatedly at different depths. Generally, however, it is used only when a single shot is required, and it is particularly helpful in securing records necessary in directional drilling.[84]

Figure 309 presents a sectional view showing the arrangement of parts in a typical single-shot instrument of magnetic type. The plumb bob *V* incorporates a pair of fine crossed wires supported by a delicate wire and chain suspension and hangs freely from the intersection of two accurately adjusted cross wires which intersect the axis of the instrument. The plumb bob is made of nonmagnetic material and is suspended so that its cross hairs are supported in a horizontal plane a short distance above the compass card *W*. The latter is mounted on a highly sensitive magnetic needle which turns freely on a jeweled support. Small incandescent lamps *R* operate on electric current supplied by dry batteries *E*, when a circuit is closed by watch *L*, which can be set to operate after sufficient time has elapsed to lower the instrument to the point in the well where the record is to be made. A buzzer *H* vibrates the instrument half a minute before the record is made, so that the plumb bob and compass settle into accurate positions. When the instrument is illuminated (for 50 sec.), lens *Q* focuses an image of the compass card and cross hairs of the plumb bob on a disk of sensitized paper cardboard, 1⅝ in. in diameter, rimmed with metal. The unexposed record disks can be forced, one at a time, into operating position in the instrument, from a daylight magazine-loading device, through slot *O*, before the instrument is lowered into the well. After the record has been made and the instrument has been withdrawn to the surface, the record disk is transferred into a light-tight developing and fixing tank, also in daylight. Thus, the record of the survey is made available soon after the instrument is withdrawn from the well. Figure 310 reproduces a typical single-shot record disk.



(Courtesy of Eastman Oil Well Survey Corp.)

FIG. 310.—Typical single-shot record disk. (Actual size; record shows deflection of 11¼ deg. in direction N. 23° W.)

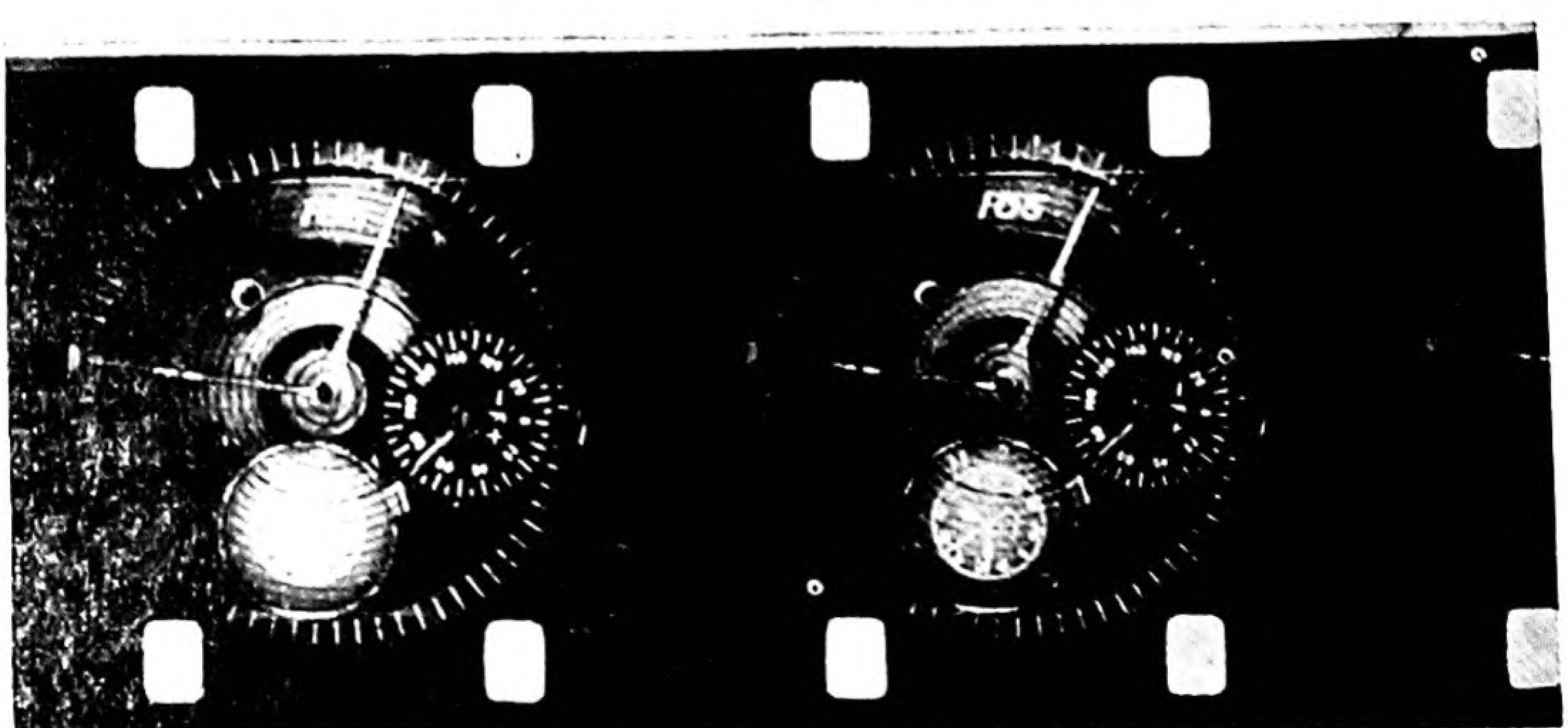
Other features of the single-shot magnetic instrument are designed to protect it during use in the well, and for convenience of access for adjustment and replacement of parts. Such instruments are obtainable in two sizes and with replaceable features adapting the pendulum to well inclinations of from 5 to 65 deg. The larger of the two sizes fits into an outer, watertight, nonmagnetic protecting case and is 60 in. long and 3¼ in. in outside diameter and weighs 34 lb. A sinker bar or a joint or two of tubing may be used in open hole to add weight and ensure proper alignment. A smaller size of instrument of similar design is available for use inside drill pipe. Inside of drill pipe or casing, the magnetic compass is unreliable as a direction indicator, but records of the inclination of the hole are dependable.

The Surwel Clinograph.—This device, which has been mentioned in an earlier section as one employing the gyroscope as a direction finder, is illustrated in Fig. 311. The amount of deflection of the well from the vertical is indicated by a box-level gauge. The instrument also contains a watch, a dial thermometer, and a special motor-

operated camera using 16-mm. motion-picture film. Dry-battery cells provide power for operating the gyroscope and camera motor and furnish light for making the photographs. The several parts are so arranged that each photograph shows the position of the gyroscope pointer, the level bubble, the thermometer and the watch dial. A series of such photographs, made at different depths in a well, afford a means of accurately and completely charting its course.

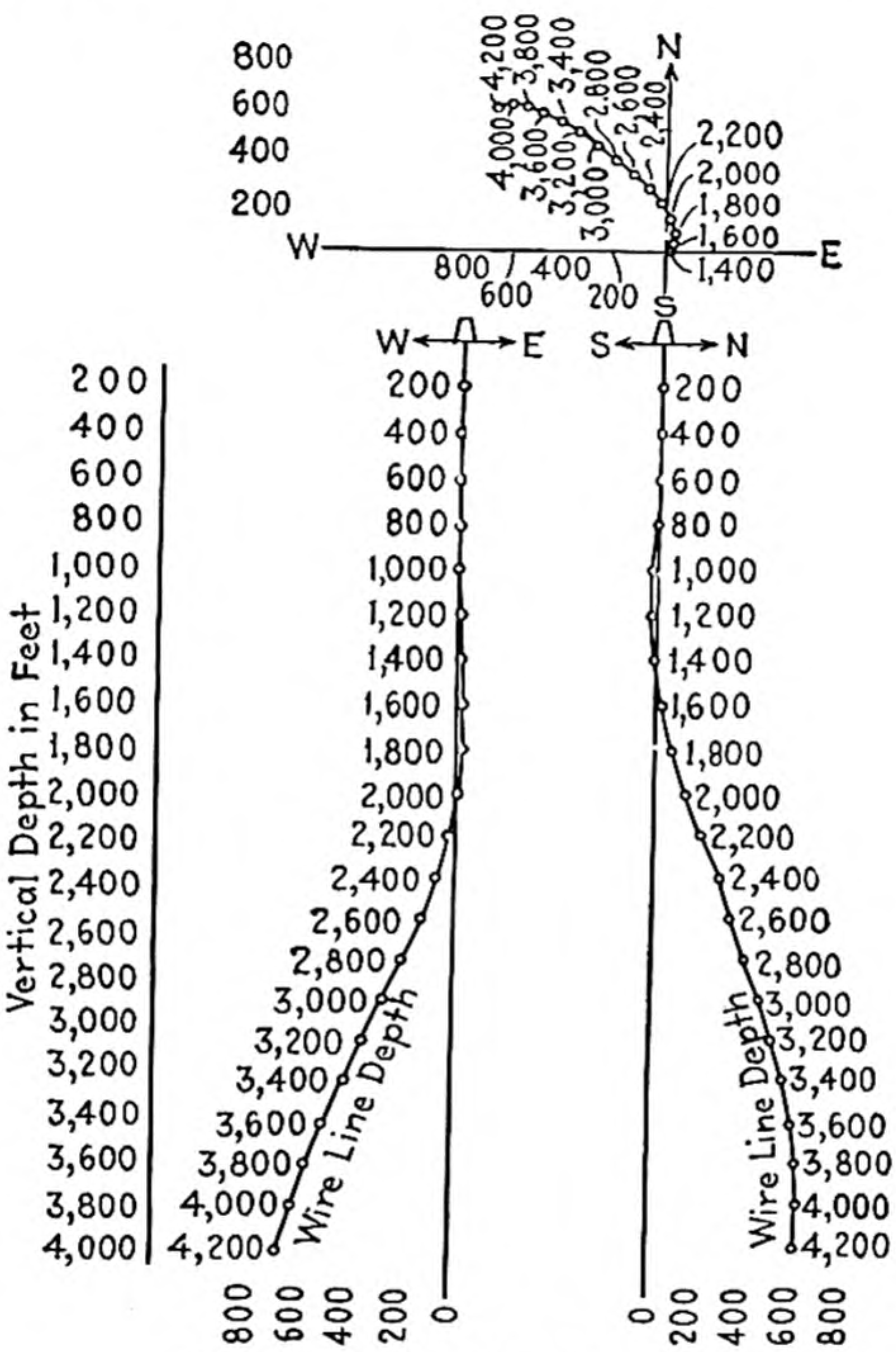
(*Courtesy of Sperry-Sun Well Surveying Co.*)
FIG. 311.—Vertical section through Surwel clinograph.

The gyroscope wheel is revolved about its axis by a small motor at from 10,000 to 14,000 r.p.m. and is balanced in such a way that it will maintain its axis in whatever plane it may be set, for a long period of time. A pointer, mounted over a compass scale, is attached to the gyroscope axis and indicates the direction of the axis of rotation. A nonmagnetic watch having three hands shows the time at which photographs are made. A large second hand on the watch makes it possible to read the time to $\frac{1}{5}$ sec. A dial thermometer, having a range of from 0 to 240°F., shows the temperature existing inside the protective casing. The camera, located immediately above the gyroscopic unit, has two lenses which record pictures taken in opposite directions simultaneously on the same film. One lens photographs the gyroscope pointer and compass scale, the watch dial and the thermometer, located below, and the other the position of the bubble in the box-level gauge immediately above the camera unit (see Fig. 312). The necessary light for making the photograph is obtained from several incandescent lamps operated by current from the dry cells through an automatic and adjustable contact device synchronizing with the movement of the film. The movement of the film is intermittent; pictures are taken while the film is at rest, at the rate of one picture for



(*Courtesy of Sperry-Sun Well Surveying Co.*)
FIG. 312.—Motion-picture film records made by the Surwel clinograph.

each 6 to 8 sec., if the instrument is lowered on a wire line into the well at the rate of about 3 ft. per sec. If it is lowered on a drill stem, a very accurate timing device is arranged on top of the box-level gauge. This timing device controls the operation of the camera motor and is so adjusted that one photograph is made for each fourble stand of drill pipe lowered. The timing device is adjustable to vary the time allowance for connecting and lowering the drill pipe from 1¼ to 2½ min. This adjustment will vary with the depth of the well, the equipment available in the derrick and the skill of the crew.



(*Courtesy of Sperry-Sun Well Surveying Co.*)

FIG. 313.—Results of a well survey projected on one horizontal and two vertical planes making right angles with each other.

The box-level gauge, located above the camera unit, has a spherical upper surface with concentric graduations etched to indicate the vertical deviation in degrees. Three different levels are provided with each instrument having maximum inclinations of 20, 40 and 55 deg., respectively. Both the bottom and top are of transparent glass. The nature of the fluid and size of the bubble are such as to damp oscillations but, at the same time, prevent lag in readjustments of the position of the bubble. The gauge is equipped with expansion coils to adjust the volume of the fluid to changes in temperature.

The three units are inserted into a steel protective casing made up in three sections and capable of withstanding outside hydrostatic pressures up to 6,000 lb. per sq. in. The lower section is provided with a steel nose and shock absorber and carries the

dry-cell batteries, the center section carries the Surwel instrument and the top section is equipped with either a wire-line socket or a sub, depending upon whether the instrument is to be operated on the wire line or on drill pipe.

When lowering the instrument, the time is closely observed by the operator on a watch synchronized with that in the instrument, thus fixing the depth at which each photograph is taken. Records are made both while descending and while ascending, and each set of records is interpreted in the direction in which it is taken. This procedure is equivalent to making two surveys, thus providing a check on the accuracy of the work. Upon the return of the instrument to the surface, the film is removed and developed. The photographs show the inclination from the vertical, the orientation as well as the time (indicating the depth) and the temperature. Corrections for

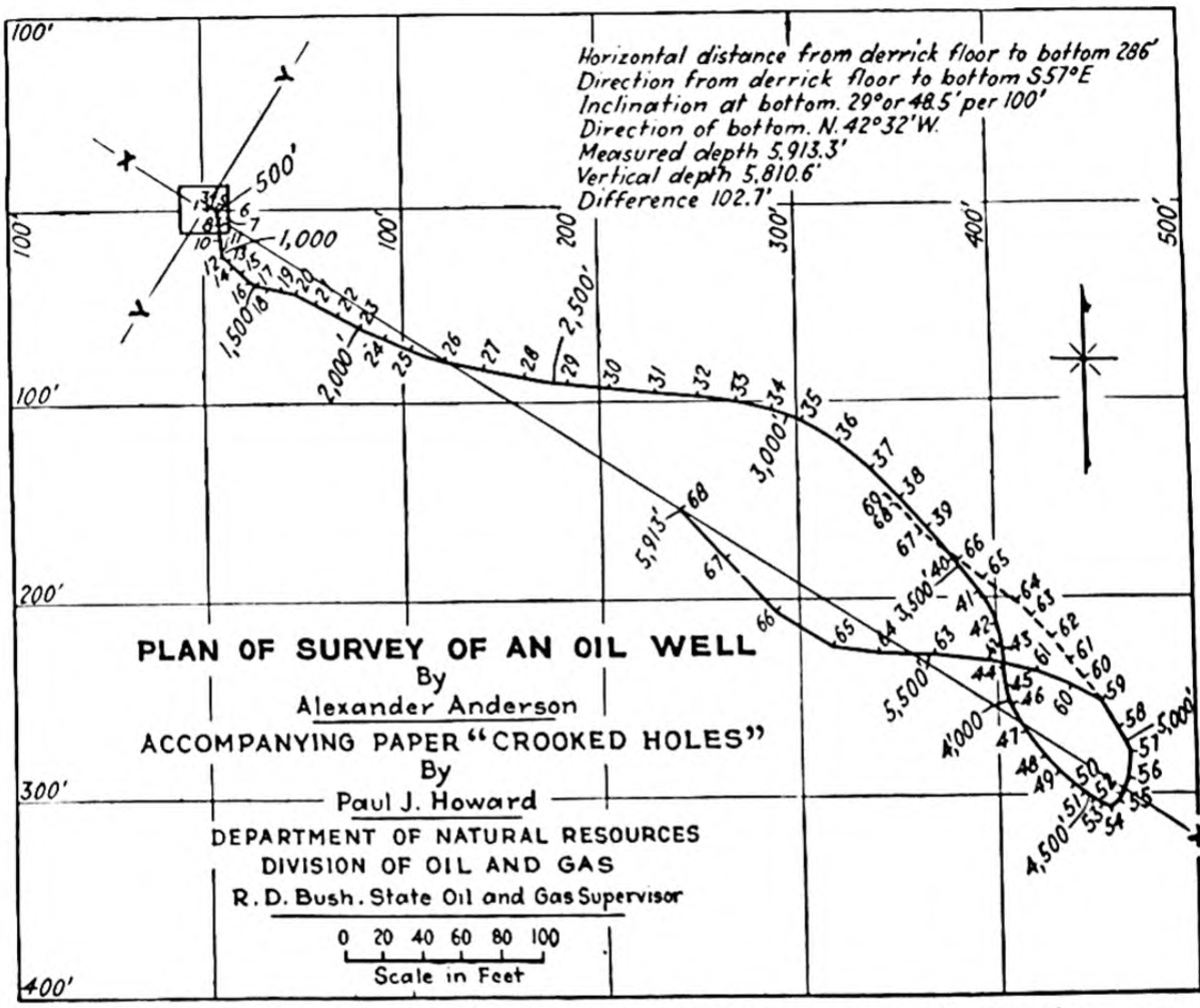


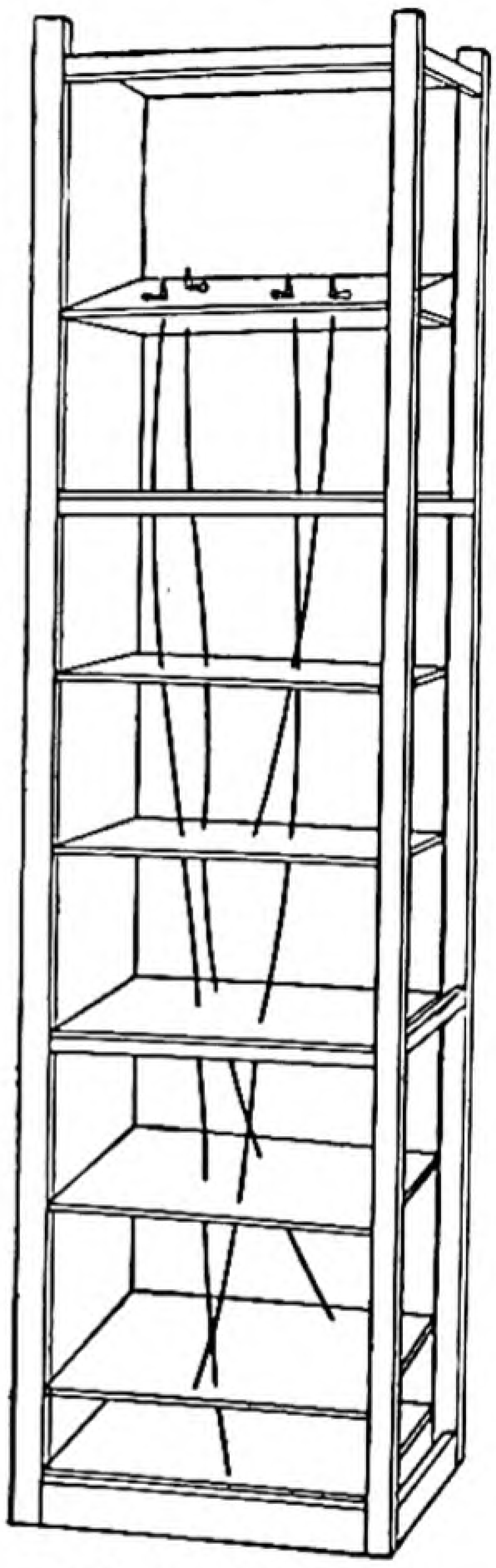
FIG. 314.—Horizontal plat of a well that followed an unusually erratic course.

the cardinal error, parallax and refraction (established for each instrument) are made, and a complete map of the well is then constructed. This map consists of three projections: a vertical projection on a north-south plane, a vertical projection on an east-west plane and a horizontal projection. From these projections, the position of the well at any reference point or plane can be ascertained with respect to the position of the mouth of the well at the surface (see Fig. 313).

The Sperry-Sun Well Surveying Company, which controls the patent rights on this instrument and undertakes the making of well surveys with it, guarantees a resurvey if the closure at the bottom of the well between in and out runs is more than 1 per cent of the depth of the well. Additional advantages are found in speedy operation, freedom from cumulative errors and independence of magnetic conditions or tortuosity in the course of the well. The service given in the application of this instrument is confidential, the film, all working sheets and the map being given to the

owner of the well. If the owner desires to be the only person who knows the results of the survey, he may develop and interpret the records for himself or he may select a direction for the gyro pointer which is known only to him.

Methods of Presenting Results of Well Surveys.—A complete representation of the course of a well is afforded by projecting its position on three reference planes making right angles with each other. One of these should be a horizontal plane. The other two may be north-south and east-west planes, or the two vertical planes may be oriented in such a manner as will best display the true inclination from the vertical. Figure 313 presents a typical projection on three planes. Figure 314 is a plan view of a well which followed an unusually erratic course. A realistic method of displaying the course of a well is illustrated in Fig. 315. This is essentially a three-dimensional model. Copper wire, bent to conform to the actual course of the well, is used to represent each of the four wells pictured. Horizontally placed screens may be used to mark the major reference horizons. A convenient scale for such a model is 100 ft. per in.



(*After M. Van Couvering in Am. Assoc. Petroleum Geologists Bull.*[96])

FIG. 315.—Three-dimensional model illustrating courses of oil-well drill holes.

GRAPHIC METHODS OF RECORDING FIELD DATA

Field Maps.—Field maps are constructed by first drawing a map of the property lines, together with the railroads, highways, town sites and other permanent improvements, in as much detail as desired or as the scale of the map will permit. Ownership of various properties, section and township lines and numbers are also carefully lettered. Using this base map as a frame, all wells are then located to scale with reference to property lines or section corners. The position of each well is indicated by a small circle, using conventional symbols (see Fig. 316) in connection therewith to indicate whether the well is a drilling well, a producing oil well, a gas well, a dry hole, a well abandoned in process of drilling, a well temporarily idle or an abandoned producer. The number of the well, or the name by which it is known, is lettered at one side of the symbol marking its position, and, if the scale of the map permits, the elevation of the derrick floor and the depth of the well may also be indicated; and perhaps, also, the initial production.

Figure 317 illustrates a typical field map. It is obvious that to serve its intended purpose, which is primarily to show in a broad way the extent of development in different portions of the field, the map must be

of rather small scale; otherwise it becomes unwieldy. Scales of 2,000 or 1,000 ft. to the inch are commonly used for this type of map. These are large enough to permit of showing the positions of the wells, their numbers, names of property owners, etc., but do not allow space for much further detail.

Property Maps.—Maps of larger scale, often 200 or 300 ft. to the inch, afford opportunity for indicating the position of wells, derricks and rigs, buildings, tanks and reservoirs, pipe lines, roads, telephone lines, fences and other structures in full detail. Such maps are called "property maps" to distinguish them from the smaller scale field maps. The map shown in Fig. 318 is typical.

Vertical sections on which the structural and stratigraphical features may be displayed to good advantage are conveniently constructed with

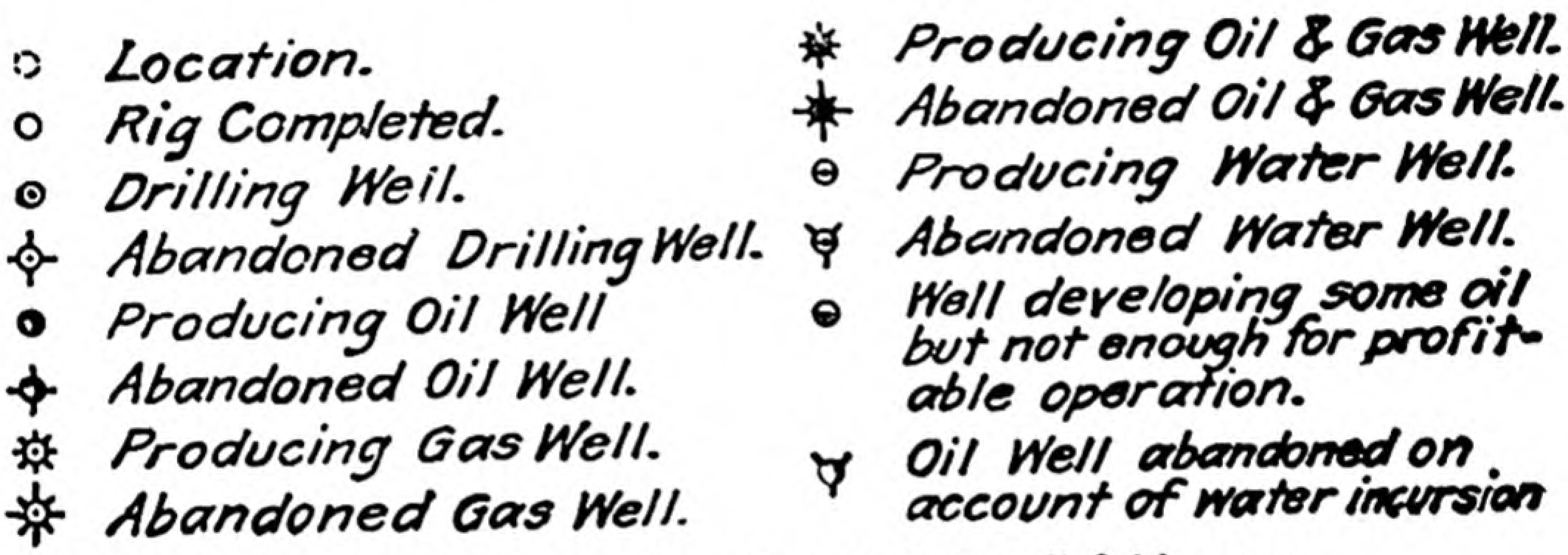


Fig. 316.—Conventional symbols for oil-field maps.

the aid of graphic logs prepared as described in an earlier section. Cross sections developed in this way are most useful in studying the underground conditions in oil fields. The formations are determined by the drilling records, and the cross sections are used to correlate these formations from well to well. Even in a region of simple geologic structure and stratigraphy, cross sections are necessary to bring out the local variations in structure. Irregularities of well depths and casing depths can also be studied to advantage with the aid of cross sections. They form, in fact, the basis of the work of the engineer and geologist in studying underground losses and methods of improving recovery (see Fig. 319).

The selection of the position of the cross section involves choosing a line of wells that will give sufficient information and that lies in the desired position with respect to the axes of the structure. Usually, it is desirable to have one or more cross sections plotted at right angles to the major axis of the structure and one parallel with the major axis. To aid in correlating, it is particularly desirable to have one or both end wells of each cross section overlap, that is, the log of the end well should also be plotted on some other cross section. The graphic log of every well on a property should be plotted on at least one cross section. If it happens that a particular well falls a little to one side of a desired cross section, it is often possible to project it into the plane of the cross section by reference to known marker horizons, or by an actual

calculation of equivalent positions with respect to the known dip of the formation. The individual logs may also be correlated by reference to an assumed datum line, such as sea level (see Fig. 320).

There are two general methods of preparing cross sections: one in which the graphic well logs are plotted on a single piece of tracing cloth, properly spaced apart

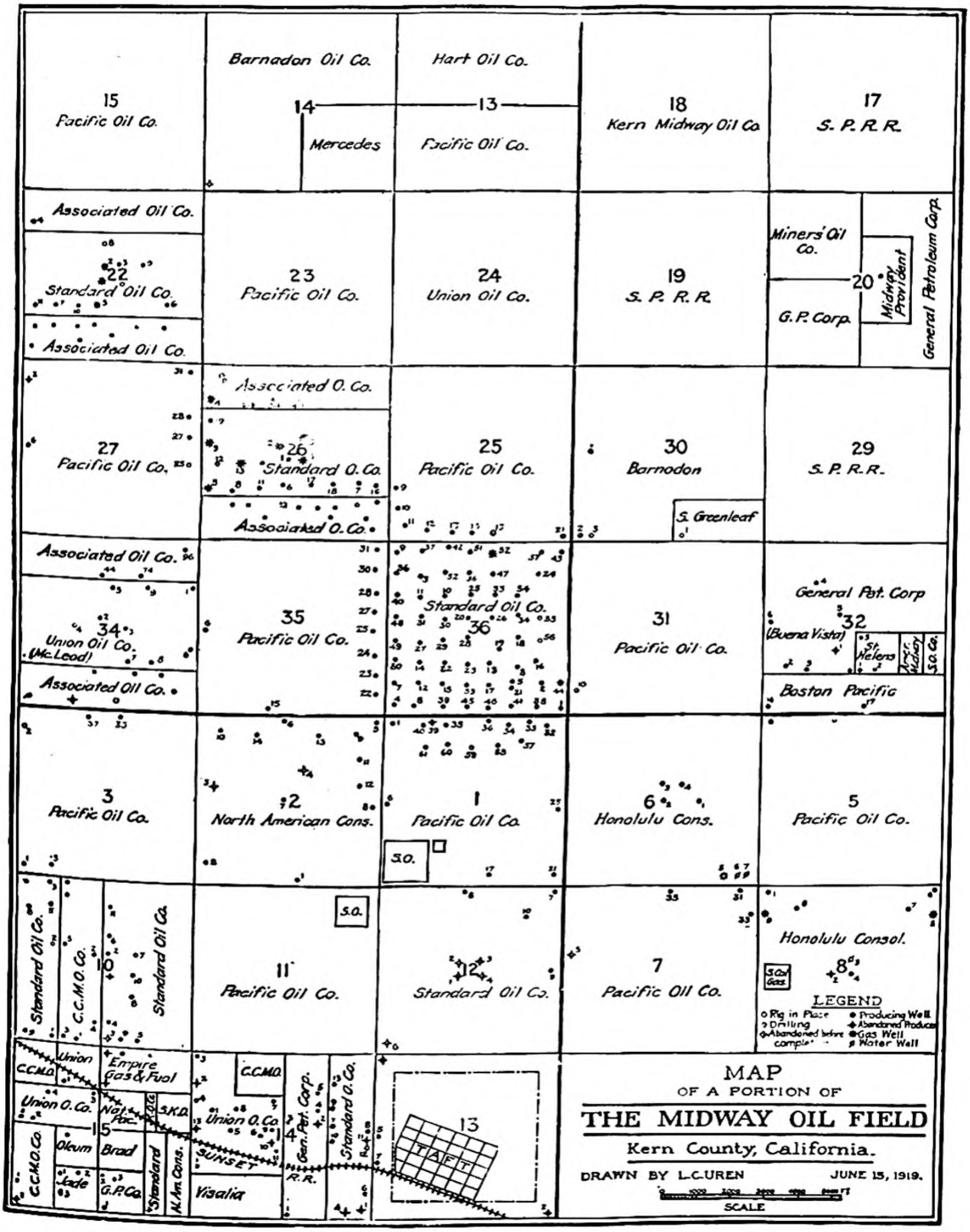


FIG. 317.—A typical field map.

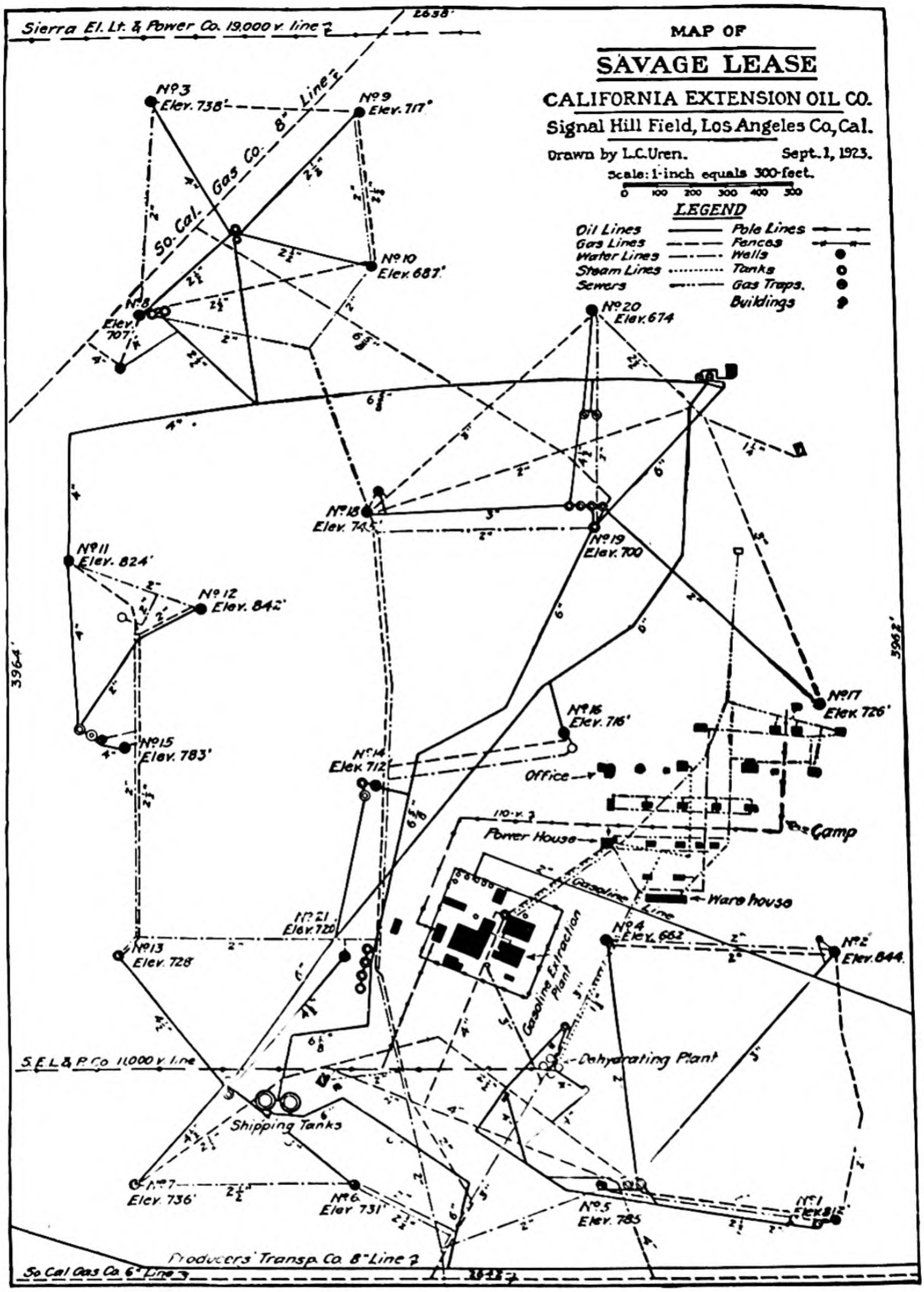


FIG. 318.—A typical property map. The property is only partially developed. Wells produce both oil and gas and are operated by individual gas engines. Buildings may be conveniently numbered with reference to a list giving purpose and dimensions of each.

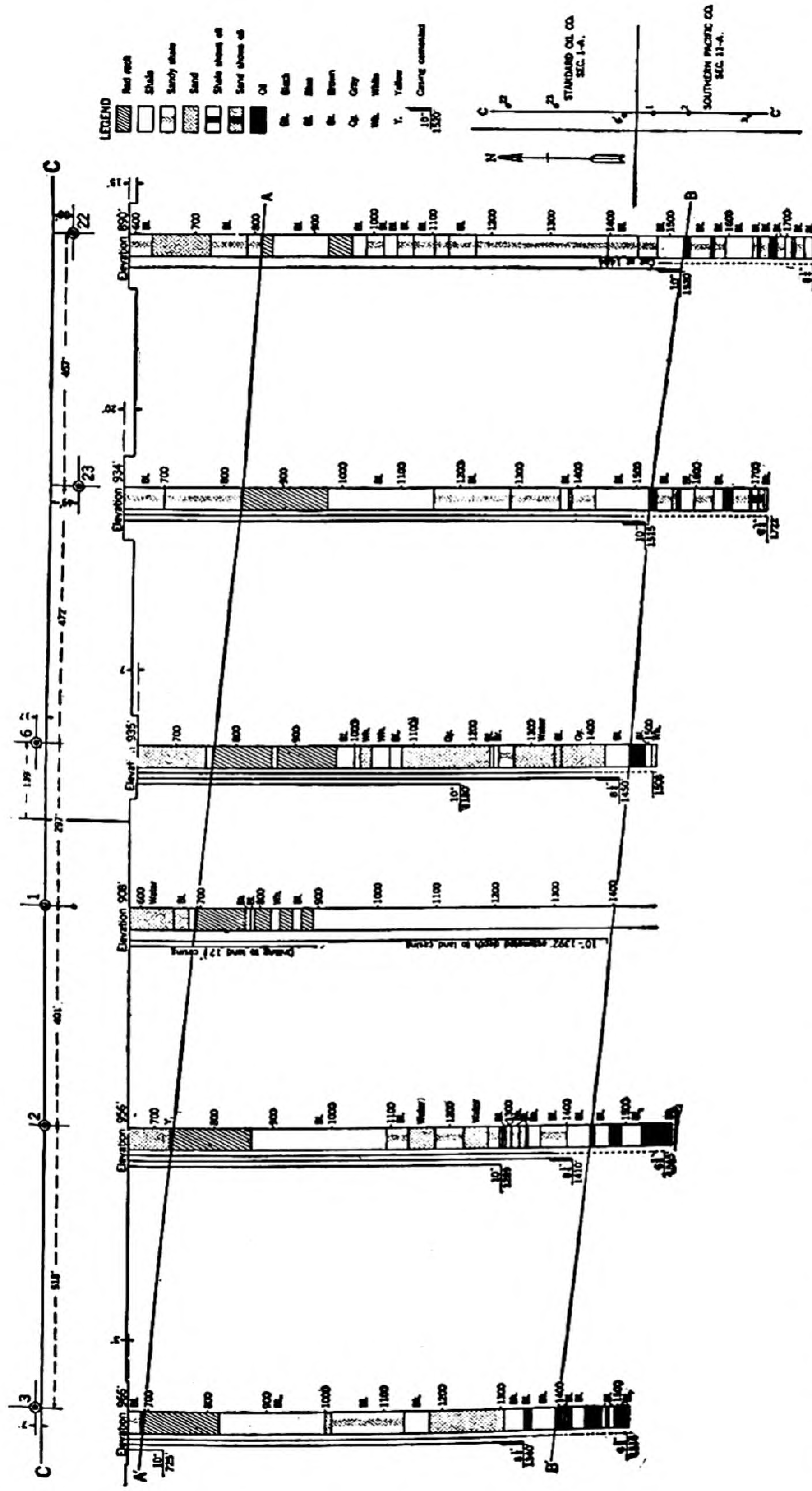


FIG. 319.—Development of geologic sections by correlation of well logs. Lines AA' and BB' represent correlations of marker horizons. (*After R. E. Collom in U. S. Bur. Mines Bull. 201.*)

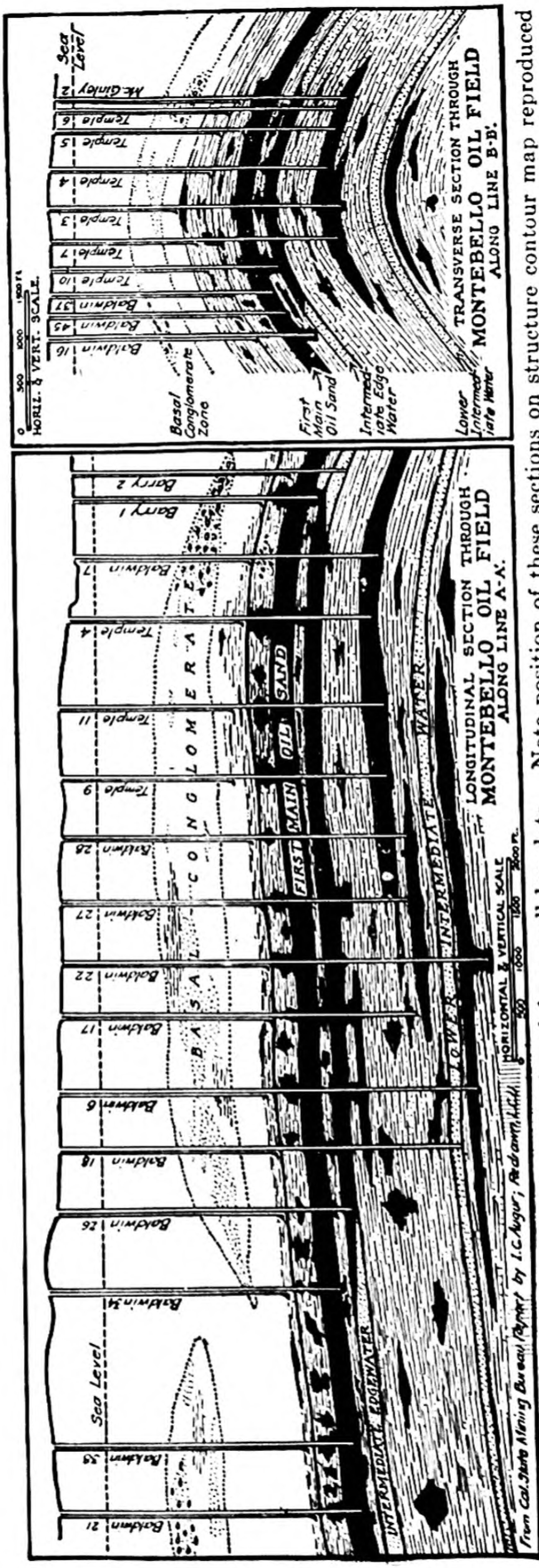


FIG. 320.—Typical geologic sections developed from well log data. Note position of these sections on structure contour map reproduced in Fig. 321.

to the scale selected; and the other where the graphic logs are plotted separately on strips of tracing cloth and are arranged at proper distances apart to form the desired cross section. In the latter plan, each graphic log has to be plotted only once, serving in turn for as many different cross sections as may be desired.

Most engineers prefer to construct vertical sections by blue-printing from the graphic log tracings. The graphic log tracings are placed in the printing frame, properly spaced apart on an assumed horizontal scale and adjusted with respect to an assumed datum line. For convenience, we may have a horizontal line ruled on the glass against which the print is made and adjust the sea-level points of all tracings so that they fall on this line. This automatically accounts for differences in elevation of the derrick floors. We may also have marks along the top and bottom of our blue-print frame to serve as a scale, which aids in spacing the logs at the proper distances apart and in keeping them in a vertical position. With a series of logs arranged in the frame in this way, a blueprint is made on one sheet of paper which becomes a permanent copy of the logs as arranged. This print may be later used in developing a completed section.

In order that lines may be drawn on this section, it is desirable to use a positive or blue-line print, which, of course, necessitates making a brown-process negative. Corresponding horizons on different wells in the cross section are first connected with straight lines, and the intervening space between logs may then be worked up in full geologic detail if desired. The appearance is greatly improved by the use of crayon or water color applied in such a way as to develop suitable distinctions between the different strata.

Instead of blueprinting sections in this manner, we may photograph the well logs after properly arranging them to form the desired section. The photostat, a device for making photographic prints directly on bromide paper, is most useful for making the prints if this plan is followed. The photographic prints are then used as a base on which to develop the complete geologic detail if desired.

The cross section should show the number of each well in the section, its elevation, production data, etc., and there should be a supplementary key map indicating the line of the cross section. Every cross section should also have a suitable title (see Fig. 320).

Underground Structure Contour Maps.—Well logs are also useful in constructing what is called an "underground structure contour map." Such a map shows, by means of contours connecting points of equal elevation, the position and form of an unexposed bed such as the top of an oil sand, over a large area.

Before starting work on a structure contour map, the datum plane must be chosen—this is usually sea level. The contour interval must also be decided upon, and this usually depends upon the nature of the structure, its dip, the data available, the scale adopted and the purpose for which the map is to be used. The contour interval, or distance between successive contours, is frequently 25 or 50 ft.

By a study of well logs or cross sections, the distance between the bed to be contoured and the datum plane is computed for each well and written down beside the well's position on the map. Interpolation between known points determines the elevations of other points. Contours are

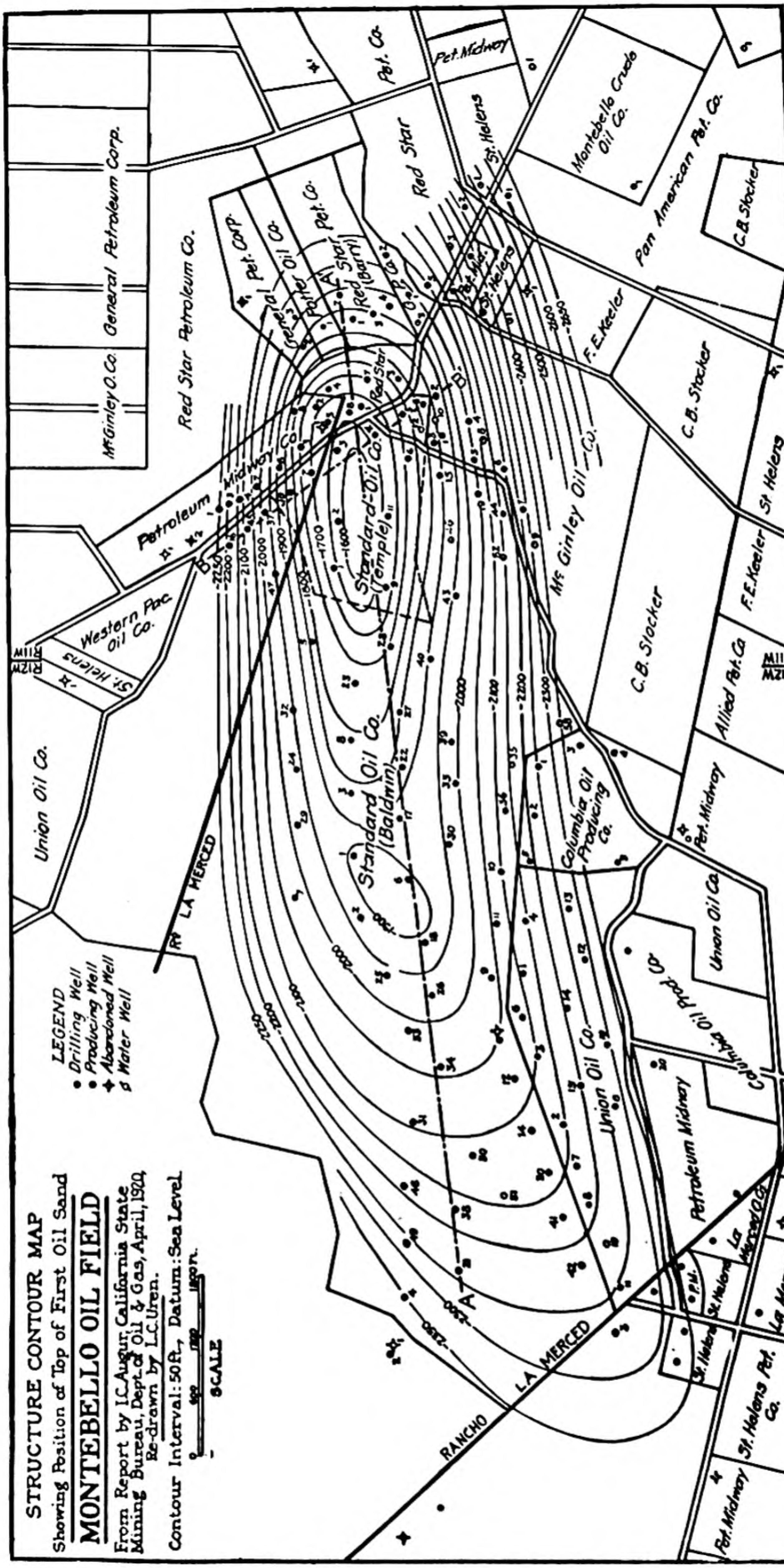


FIG. 321.—A typical structure contour map developed from well log data. Note that vertical sections along lines *AA'* and *BB'* are reproduced in Fig. 320.

then sketched in at regular intervals with respect to the elevations so determined (see Fig. 321).

The chief value of such a map is to display broad structural features over a large area in a way not equalled by even the most careful study of geologic cross sections. An underground structure contour map can often be used to show the location of wells relative to folds in the formation, or the most favorable undrilled tracts for the production of oil and gas, and it may be used as an aid in the selecting of well sites. It is also possible with a carefully prepared structure contour map to predict with fair certainty the necessary depth of a well to be drilled at any designated point to intersect the oil sand. The map also serves to indicate the direction and amount of dip of the structure at any point.

Convergence Maps.—Still another type of map which is useful in some ways and which can be developed from well log data is the convergence map. This type of map indicates, by means of contours, the difference in elevation at any point between two irregular and nonparallel horizons. It may show, for example, the difference in elevation between the surface of the earth and the top of a submerged oil sand. The convergence map is constructed in much the same manner as the structure contour map, calculating the distance between the two horizons at various points from the known rate of convergence and connecting points having the same difference in elevation with contour lines.

Peg Models.—The most satisfactory method of demonstrating the structural conditions disclosed by a series of well logs is by constructing what is called a "peg model." Peg models have a great advantage over maps and sections in that they present the data directly in three dimensions instead of two, so that we obtain an actual picture of the situation. The method has been found especially useful to the nontechnical man, who grasps readily the essentials from a model, whereas cross sections and contour maps are apt to be confusing.

Peg models are widely used in making correlations of structure between one well and a group of others and are especially useful in determining the proper points at which to cement off water in a drilling well, in predicting the position of oil, gas and water sands, the proper position for casing perforations, casing depths, etc. Any marked irregularities in well depths are brought out at once by inspection of such a model.

A peg model is easily made.* First a baseboard of suitable size must be prepared. The baseboard should be made with mortised ends so that it will not warp, should be planed smooth on top and should be about 1½ in. thick. It is customary to cut

* Case, J. B., and Thompson, H. B., Peg Models: Their Construction and Use, *Summary of Operations, California Oil Fields*, May, 1921, pp. 5–21. Sixth annual report of the California State Oil and Gas Supervisor.

the baseboards so that they represent, according to some assumed scale, the area of a section or quarter section of land. The scale used is often 100 ft. to the inch. The well locations and property lines, names of property owners, etc., are then carefully scaled off and indicated on the baseboard, developing what is in effect a rough map of the area represented.

At each well location a hole is drilled with a drill press to a uniform depth, usually about 1 in. Care must be taken in boring these holes that they are absolutely vertical; otherwise the pegs will not stand vertically above the board. The pegs used may be of seasoned pine, about ½ in. in diameter. All pegs should be of the same diameter and length. These pegs or dowels can be turned out by any planing mill at reasonable cost.

A blueprint of a graphic log, drawn on a scale of 100 ft. to the inch, is then cut just wide enough to wrap around the peg and is glued on to the peg. The logs should be mounted on the pegs so that the sea-level, or datum, line, in each case lies in the same horizontal plane or at the same distance from the lower end of the peg. To accomplish this, the pegs are marked a certain distance from the baseboard, and the sea-level line, or other datum line of the log, is glued opposite that mark. The datum plane thus established should be far enough above the baseboard to allow the deepest wells to be shown to their full depths. The pegs should be long enough to show all formations penetrated by the well with the highest surface elevation.

The pegs representing different wells are then placed in their corresponding holes in the baseboard, and the principal oil or water sands are correlated by means of bright-colored threads running from peg to peg. Usually, also, one definite marker is shown by means of a certain colored string. Push pins with colored enameled heads may be used to advantage on the pegs, to indicate water shutoffs and other important features of the work.

One of the larger oil companies uses small aluminum or steel rods (¼ in.) instead of wooden pegs, and the formations are painted on the rods with the aid of a lathe. Others use glass tubes about ¾ in. in diameter instead of pegs, the tubes being filled to appropriate depths with carefully washed drill cuttings from the various formations penetrated. A paper strip log may be glued on the outer surface of each glass tube in such a way as to leave part of the glass clear for observation of the drill cuttings.

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FILMS AVAILABLE FROM THE OIL INDUSTRY

The following list of motion pictures can be used to illustrate some of the material in this book. These films can be secured from the sources listed. In some cases, they can be secured from your local film library or local film distributor.

The running time (min), whether it is sound (sd) or silent (si), and whether it is black and white (B&W) or Kodachrome (Kd) is listed with each title.

The title in many cases adequately describes the material in the motion picture. In doubtful cases, a brief description is given with the title.

U. S. BUREAU OF MINES, PITTSBURGH, PENNSYLVANIA

Through Oil Lands of Europe and Africa—Germany, France, Spain, Morocco, and Algeria (22 min si B&W).

Through Oil Lands of Europe and Africa—Italy, Hungary, the Danube, and Rumania (22 min si B&W).

Through Oil Lands of Europe and Africa—Poland, Greece, and Egypt (33 min si B&W).

The Evolution of the Oil Industry (44 min si B&W). Traces development of petroleum from the earliest times.

The Evolution of the Oil Industry (34 min sd B&W). (Sound edition of film listed above, but content differs somewhat.) Also traces development of petroleum from earliest times to the present.

INTERSTATE OIL COMPACT COMMISSION, OKLAHOMA CITY, OKLAHOMA

Oil for Tomorrow (30 min sd Kd). Story of America's oil resources.

SHELL OIL COMPANY, PUBLIC RELATIONS DEPARTMENT, NEW YORK 28, N. Y.

Ten Thousand Feet Deep (20 min sd B&W). Modern methods of exploration and drilling for oil.

Oil from the Earth (18 min sd B&W). Locating, drilling, and transporting oil from the well to the refinery.

Oil for Aladdin's Lamp (28 min sd B&W). Describes the development of petroleum production in the research laboratory and the necessity for continued petroleum research.

STANDARD OIL COMPANY OF CALIFORNIA, PUBLIC RELATIONS DEPARTMENT, SAN FRANCISCO 20, CALIFORNIA

Oil Fires (45 min sd B&W). Their prevention and extinguishment.

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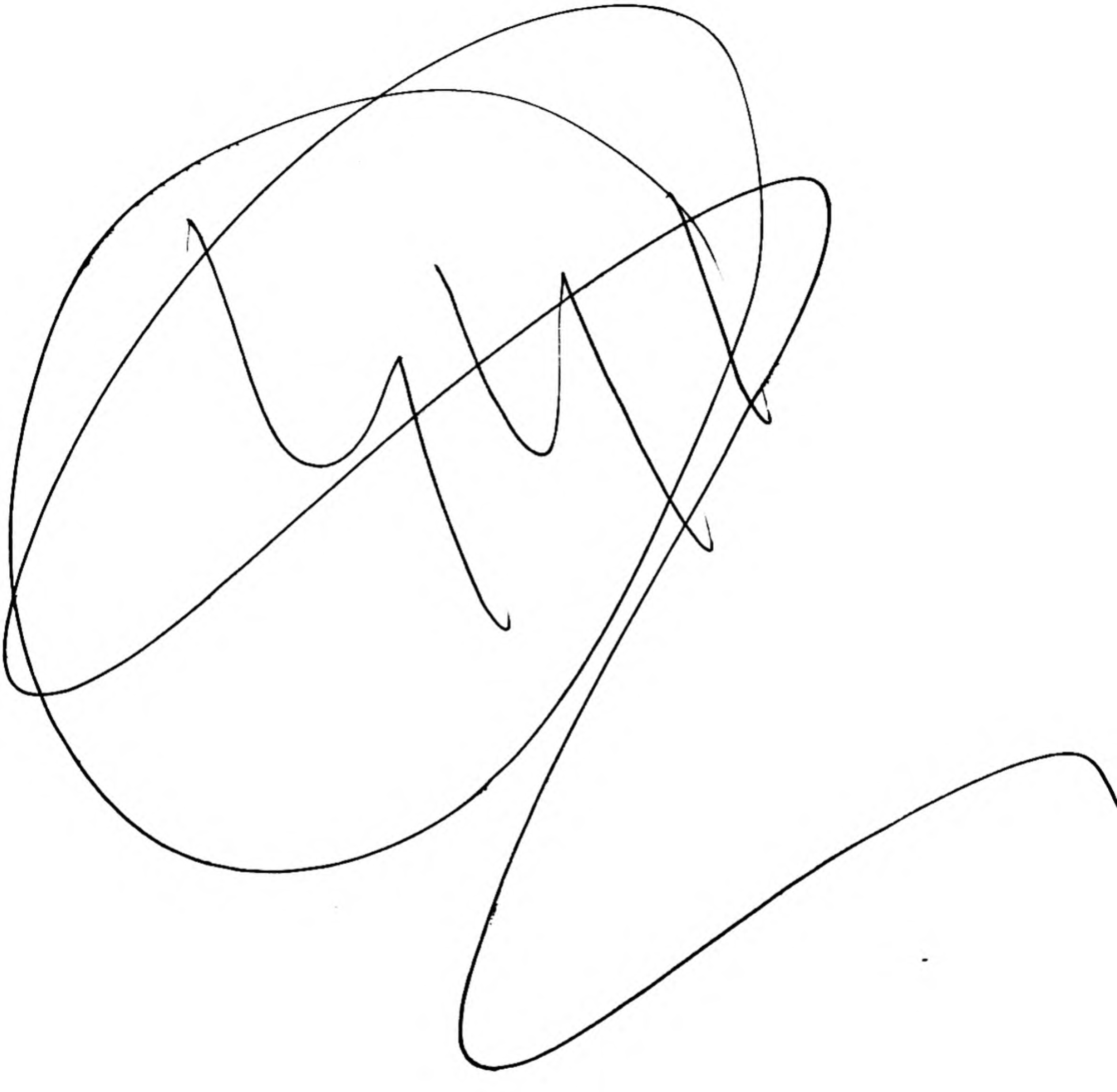

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